Annual Report to Alaska Department of Environmental Conservation

Commitment to Corrosion Monitoring

Year 2002

Prepared by

Corrosion, Inspection and Chemicals (CIC) Group
BP Exploration (Alaska) Inc.

March 2003

Commitment to Corrosion Monitoring

Year 2002

Executive Summary

This is the third annual report that meets the commitment made by BP to the State of Alaska to provide a regular review of BP's corrosion monitoring and management practices for non-common carrier pipelines on the North Slope. The contents of this report reflect the Work Plan[1] agreed jointly between BP, Phillips and ADEC, the Guide for Performance Metric Reporting[2], and feedback from ADEC on the 2000 and 2001 reports.

The report provides an overview of the corrosion management process, and provides data and discussion of the corrosion control, monitoring, inspection and fitness-for-service programs. These individual programs, in concert, form the core of the integrity/corrosion management system designed to deliver our corporate goal of no accidents, no harm to people and no damage to the environment. The program also reflects the core values of BP: innovation, performance driven, environmental leadership and progressive.

Innovation is evident in several areas, from the development of more effective corrosion inhibitors and corrosion inhibition programs, to the application of new inspection technologies. These innovations are only made possible by working closely with partners, major suppliers and the regulatory community, to bring the best available technology to Alaskan oilfields.

Performance management and the drive for improved performance are central to all aspects of the corrosion management program. This report demonstrates an on-going effort to improve corrosion management. Over the last decade corrosion rates have been reduced by almost a factor of 10 in the cross-country pipelines that transport a mixture of oil, water and gas. Consistent with the pledge to report openly both good and bad performance, the report highlights areas for improvement and the plans in-place to deliver performance improvement.

Environmental protection and corrosion management are closely linked. The improvements in corrosion management have resulted in lower corrosion rates and a lower risk of loss of containment. Opportunities to improve environmental performance still exist and the expansion of the external corrosion inspection program in 2002 is evidence of this on-going commitment.

Progressive evolution of the corrosion management programs is an on-going activity driven by changing field conditions and the desire to improve performance. Progress involves the continued refinement of the existing

[1] Appendix 2 (a) 2000 Work Plan
[2] Appendix 2 (b) Guide for Performance Metric Reporting

programs, but also, the development and implementation of new programs and corrosion management technologies.

In summary, the current corrosion management process has delivered a significantly improved level of corrosion control that has reduced corrosion rates in the cross-country flow lines by a factor of 10 in the last 10 years. Notwithstanding the successes of the last 10 years the corrosion management program must remain focused on the future in order to maintain the current level of control and, where necessary, implement the actions necessary to improve performance.

The continuous improvement of the corrosion management programs delivered over the last 10 years has enabled BP to deliver the programs strategic objectives of,

- Minimizing the health, safety and environmental impacts of loss of containment due to corrosion
- Providing a fit-for-service infrastructure for the remainder of field life
- Ability to produce satellite accumulations through existing equipment and pipe-work
- Provide an infrastructure capable of supporting gas sales in the future

In addition, with the information in this report, BP intends to build a healthy relationship with the North Slope stakeholders through consultation, open reporting and striving to raise the standards of the industry.

BP Exploration (Alaska) Inc.
March 2003

Foreword

This is the third annual report that meets the commitments made by BP in the Charter Agreement for Development of the Alaskan North Slope. The structure of the report is similar to that of prior years.

In addition to the requirements setout in the Work Plan and the Guide to Performance Metric Reporting, BP has provided additional material that is intended to provide additional context and background to aid in understanding the corrosion management program and the corrosion problems encountered in the flow lines on the North Slope.

The report is divided into 2 main sections.

Part 1 contains information regarding the BP operated fields within the Greater Prudhoe Bay (GPB) Business Unit. This consists principally of fluids produced from Prudhoe Bay, Lisburne, Point McIntyre and Niakuk field areas but also includes smaller volumes of fluids from satellite accumulations.

Part 2 contains information regarding the BP operated fields within the Alaska Consolidated Team (ACT) Business Unit. This consists principally of fluids from Endicott, Badami, Milne Point and Northstar field areas. As with GPB, several smaller satellite accumulations are also produced through ACT facilities.

There are 5 appendices. Appendices 1-4 apply to both parts of the main report, and Appendix 5 contains the detailed data tables for GPB and ACT.

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Charter Agreement – Corrosion Related Commitments

Section A Charter Agreement – Corrosion Related Commitments

The BP contact for all corrosion matters relating to the Charter Agreement is,

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Section A.1 Project Achievements

Oct-Nov 2000	Work Plan agreed between BP/PAI and ADEC Details of the Work Plan in Appendix 1
March 2001	1st Annual Report submitted to ADEC
April 2001	1st 2001 Meet and Confer session held
Oct-Dec 2001	Consultations with ADEC and ADEC's consultant
November 2001	2nd 2001 Meet and Confer session held
Dec 01-Jan 02	Developed and agreed corrosion management metrics
February 2002	BP/PAI and ADEC agreed performance metrics Details of the Performance Metrics in Appendix 2
March 2002	2nd Annual Report submitted to ADEC
April 2002	1st 2002 Meet and Confer session held
November 2002	2nd 2002 Meet and Confer session held

Section A.2 Annual Charter Timetable

March 31st	Annual Report submitted
April 30th	1st Semi-Annual Review/Meet and Confer
October 31st	2nd Semi-Annual Review/Meet and Confer

Part 1

Greater Prudhoe Bay Business Unit

Section B

Corrosion Monitoring Activities

Section B Corrosion Monitoring Activities

This section summarizes the Corrosion Management System (CMS) in use at Greater Prudhoe Bay (GPB) Business Unit. The GPB Business Unit incorporates Prudhoe Bay, Point McIntyre, Lisburne and Niakuk oilfields plus a number of smaller satellite accumulations all of which are produced through the main separation facilities.

A map and brief description of each field and the associated production facilities can be found in Appendices 3 (a) and 3 (b). Appendix 4 contains a schematic of a typical production facility configuration.

Section B.1 Corrosion Management System Strategic Objectives[3]

The following section provides an overview of the corrosion management process used within BP. The overall objective of the program is to meet the corporate objectives of 'no accidents, no harm to people and no damage to the environment'[4] which translates for corrosion management within BP to delivering a mechanical integrity program which,

- Minimizes health, safety, and environmental impacts of corrosion resulting from a loss of containment
- Provides an infrastructure fit-for-service for the remainder of the life of the oilfield
- Provides infrastructure of sufficient mechanical integrity capable of producing satellite fields/accumulations through existing main production facilities and infrastructure
- Provides an infrastructure to support future major gas production and sales through current North Slope facilities

These overall goals and objectives are achieved through a comprehensive Corrosion Management System that consists of an integrated system of strategy, processes and programs. The main elements of the Corrosion Management System are Corrosion Monitoring, Corrosion Mitigation, Inspection and Fitness-For-Service assessment. The elements of the CMS are summarized in Table B.11 (a), (b) and (c) at the end of Section B.

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[3] In addition to Charter Work Plan, this information supplied to provide additional context and help in understanding BP corrosion management activities

[4] BP HSE Policy Statement, EJP Browne, Group CEO, January, 1999, http://www.bp.com/

Section B.1.1 Corrosion Management System

The Corrosion Management System consists of a number of major program elements, which follow a simple management process. The overall system is shown in Figure B.1.

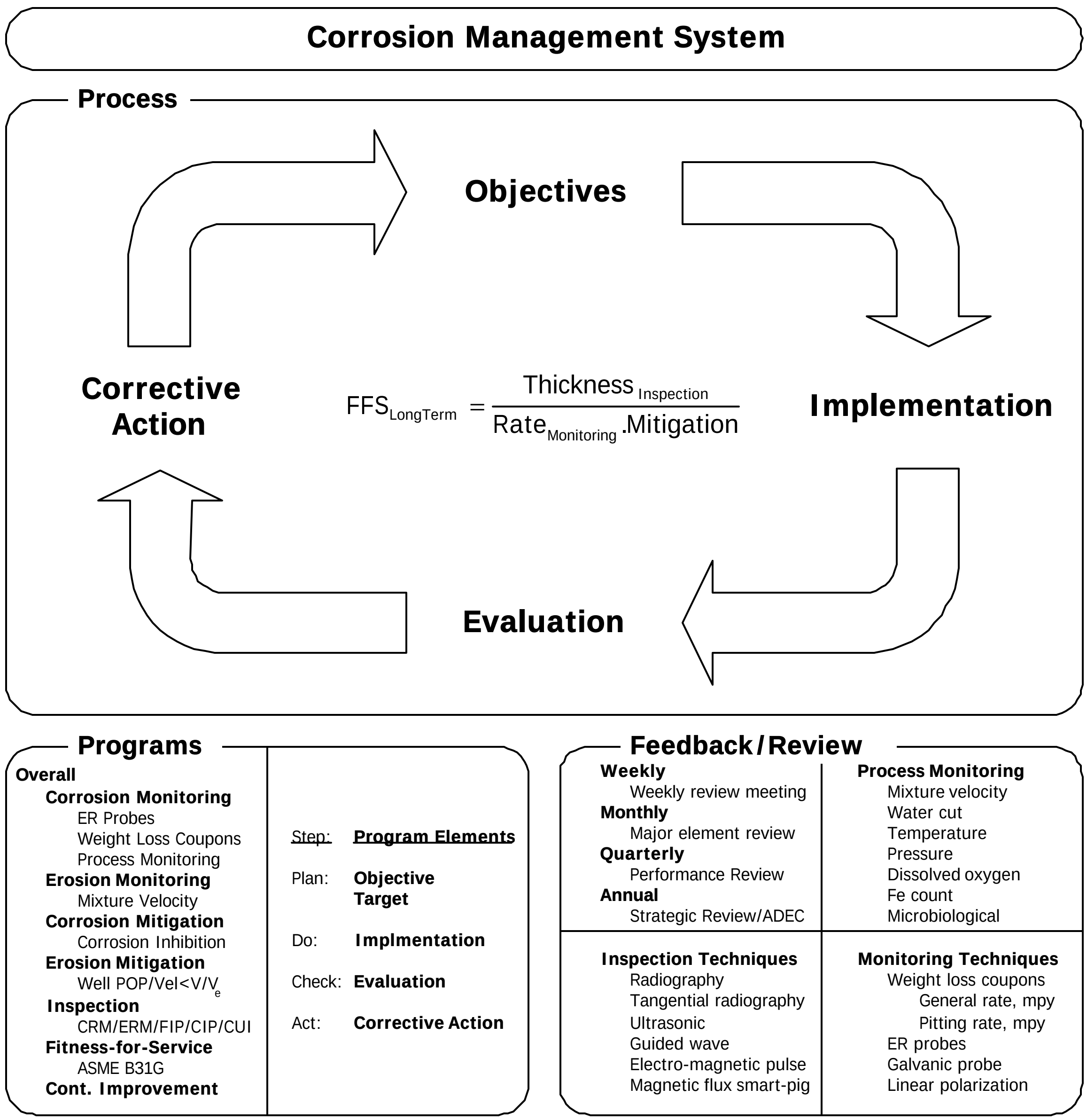

Figure B.1 Overview of the Corrosion Management Process

Section B.1.2 Corrosion Management Process

Within the overall Corrosion Management System each of the specific program elements, i.e. Corrosion Monitoring, Mitigation, Inspection and Fitness-For-

Service, follows a simple process. The management process can be described in terms of the classic TQM (Total Quality Management) process of 'plan-do-check-act' and consists of,

Step	Activity	Description
Plan	**Objective** **Target**	The program objective and purpose The metric against which performance is assessed
Do	**Implementation**	Implementation plan to achieve objective
Check	**Evaluation**	Method to evaluate performance of plan against target
Act	**Corrective Action**	The action required to correct deviation from target

Table B.2 Corrosion Management Process

The elements of the CMS program and process are also detailed in Table B.11 (a), (b), and (c).

Section B.1.3 Corrosion Management Process - Evaluation

Within the Corrosion Management Process (CMP) the results from each of the corrosion management programs are reviewed on a regular basis to provide feedback and to take any necessary corrective action based on deviation from target performance. In general, the major review cycles within the CMP are,

Review	Description
Weekly	A weekly internal review meeting at which the latest corrosion monitoring, mitigation, inspection and process data is analyzed and reviewed, and any tactical changes implemented
Monthly	Monthly summary of the major elements of the program are reviewed for the need for longer term corrective action
Quarterly	Quarterly strategic performance review held in order to ensure that the implementation plan is delivering the strategic objectives
Annual	Annual program and strategy review designed to review the strategic direction of the program and review effectiveness of the current programs in delivering the strategic direction, e.g. Annual Report to ADEC

Table B.3 Summarizing Corrosion Management Feedback Cycle

Based on the results of the evaluation process, corrective action plans are developed and the overall management program and strategic direction are reviewed.

Section B.1.4 Corrosion Measurement Techniques

The data summarized in the remainder of this report is used by the Corrosion, Inspection and Chemical (CIC) Group as part of the overall Corrosion Management System. There are a number of different corrosion monitoring and inspection techniques each of which has both advantages and disadvantages. The advantages and disadvantages, or strengths and weaknesses, make the results from the individual techniques more or less applicable depending on the application circumstances.

Table B.12 (a), (b) and (c) summarize the main categories of corrosion and process monitoring, inspection techniques and briefly summarizes relative strengths and weaknesses for different applications.

Section B.1.5 Integration of Monitoring, Inspection and Mitigation

The elements of the corrosion management program have to be applied to each of the systems on the North Slope to reflect their applicability and efficacy. The corrosion and erosion monitoring, inspection and mitigation practices for the major services and equipment type are summarized in Table B.13.

Section B.2 Inspection and Corrosion Monitoring Activity Level

Figure B.4 summarizes the level of internal and external inspection activity across GPB since 1995 for both cross-country flow lines and well lines. The 2002 internal inspection activity of ~26,000 was only slightly above the 1995-2001 average of 24,500 and therefore consistent with historical levels of activity. As can be seen from Table B.6, the level of external corrosion inspection activity has been increased significantly in 2002 from the 5-year average of ~13,000 to ~43,000 locations.

The 2002 external corrosion inspection activity was significantly above the 35,000 locations forecast in the 2001 report. This was primarily due to the accessibility of the locations in the 2002 survey. The ease of accessibility in 2002 is not expected to be repeated in 2003 and therefore the 2003 forecast activity level for external corrosion inspection is 35,000 consistent with the original 2002 forecast.

Figure B.4 also shows the breakdown of the inspection program between internal and external inspection. From the figure it can be seen that the percentage, $\frac{\text{Ext}}{(\text{Ext} + \text{Int})}$%, of the overall inspection effort consumed by the external corrosion inspection effort has increased significantly with the increased effort in 2002. As noted above, it is anticipated that for 2003 the percentage will be lower at approximately 55% compared to the 65% for 2002.

Table B.5 provides the details of inspection activity for the internal and external programs. The level of external corrosion inspection activity has been ramped-up from a broadly flat level of 10-15,000 in 1995 to over 43,000 external inspection items in 2002. Based on the results of the data generated in the 1996-2001 external corrosion inspection surveys, the 2002 program was expanded to reduce the risk of a leak because of the external corrosion. This is discussed in detail in Section E. The average activity level for the program from 1996-2001 was ~13,000 items per year, in comparison the 2002 program achieved ~43,000 items which is over 3 times the average for the prior five years.

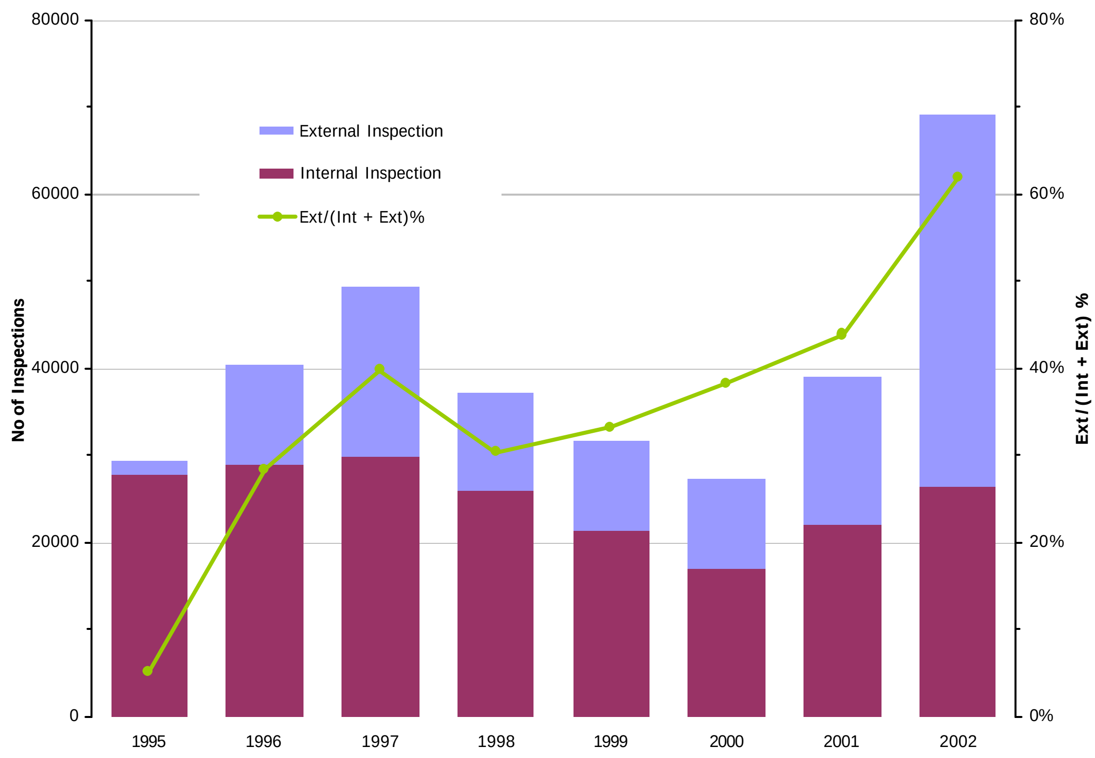

Figure B.4 Breakdown of Inspection Activity Between Internal and External for Field Piping

Year	1995	1996	1997	1998	1999	2000	2001	2002
External	1508	11509	19616	11262	10515	10441	17090	42728
Internal	27802	28998	29796	25858	21187	16836	21894	26382
Total	29310	40507	49412	37120	31702	27277	38984	69110
$\frac{Ext}{(Ext+Int)}\%$	5%	28%	40%	30%	33%	38%	44%	62%

Table B.5 Internal and External Inspection Activity Breakdown

	Year	1995	1996	1997	1998	1999	2000	2001	2002
Flow Line	External	1508	11473	17935	10316	8139	5184	3966	18931
	Internal	21769	20544	21317	18115	14870	9625	11576	13206
	Total	23277	32017	39252	28431	23009	14809	15542	32137
	$\frac{Ext}{(Ext+Int)}\%$	6%	36%	46%	36%	35%	35%	26%	59%
Well Line	External		36	1681	946	2376	5257	13124	23797
	Internal	6033	8454	8479	7743	6317	7211	10318	13176
	Total	6033	8490	10160	8689	8693	12468	23442	36973
	$\frac{Ext}{(Ext+Int)}\%$	0%	0%	17%	11%	27%	42%	56%	64%
Grand	**Total**	29310	40507	49412	37120	31702	27277	38984	69110
	$\frac{FL}{(FL+WL)}\%$	79%	79%	79%	77%	73%	54%	40%	47%

Table B.6 Internal and External Inspection Activity Summary by Flow/Well Line

Tables B.6 Shows the split between flow line and well line inspections for both the internal and external programs. The data shows that there has been a shift in the inspection program from the flow lines to the well lines. This reflects the higher degree of corrosion control in the flow lines compared to the well lines.

For the year 2002, the level of internal inspection activity for the well lines and the flow lines was approximately equal at ~13,200 items. Similarly, the external corrosion inspection program activity was approximately equally distributed between the well line and flow lines at ~20,000 items for each. The split between internal and external inspection for the flow lines and well lines is summarized in Figure B.7

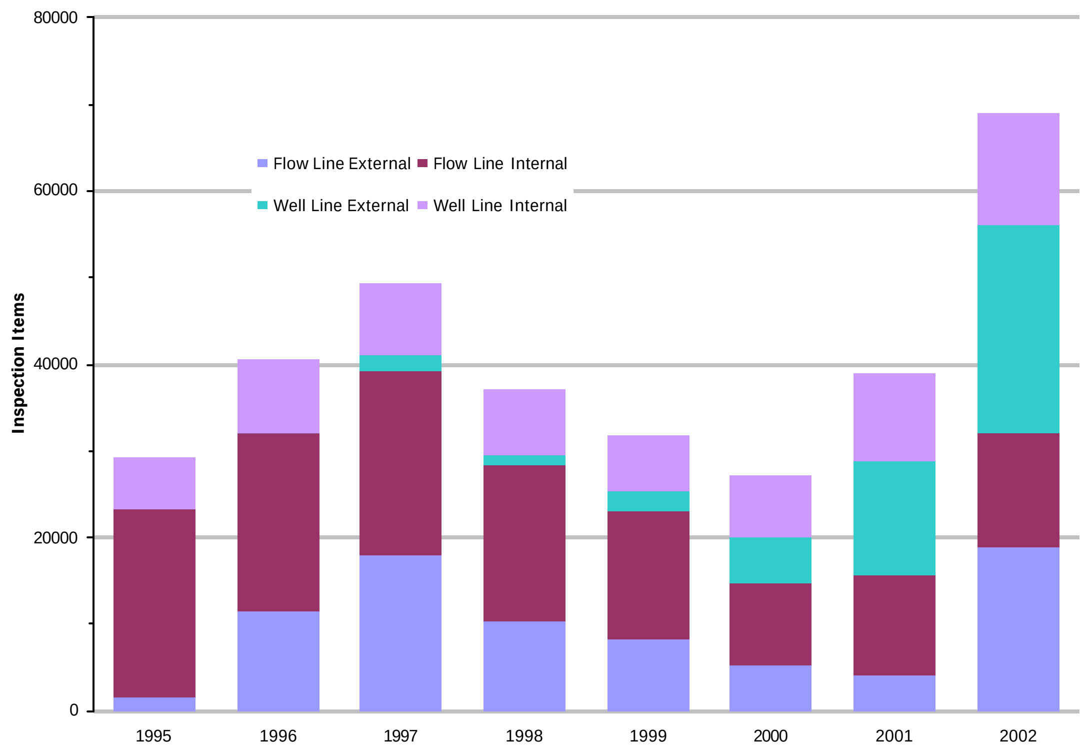

Figure B.7 Internal and External Inspection Activity Summary by Flow/Well Line

The 2002 smart pig program consisted of the examination of 3 produced water lines located on the east side of GPB. Due to the limitations of the magnetic flux leakage (MFL) technique, see Table B.12 (c), the output of the analysis of the pig run is used as a guide to the depth and location of damage in the pipeline inspected. This relative assessment of pipeline condition from the smart pig program is then incorporated into the ultrasonic and radiographic detailed inspection described above. The routine inspection program then verifies the depth of damage and the location is then scheduled for repair and/or re-inspection as necessary.

The number of monitoring locations in any given year, by equipment type and service, is summarized in Table B.8 (a). As can be seen, the table shows that the number of active locations has been approximately constant since 1995. The relatively small number of differences between years reflects the movement of lines into and out of service, the addition or abandonment of equipment, and the addition or removal of corrosion access fittings to the program.

Equipment	**Service**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**
Flow Line	3 Phase	178	181	177	178	175	173	175	177
	Export/PO	3	6	6	5	5	5	4	6
	Gas	3	3	1	1	1	1	1	1
	Other	2	2	1	1	1			
	Water	18	18	18	18	20	19	19	22
	Total	204	210	203	203	202	198	199	206
Well Line	3 Phase	1057	1172	1226	1208	1173	1169	1073	1076
	Export/PO		3	3	3	3	3	3	
	Gas	7	9	7	7	7	7	7	8
	Water	182	187	191	188	181	175	172	180
	Total	1246	1371	1427	1406	1364	1354	1255	1264
Grand	**Total**	1450	1581	1630	1609	1566	1552	1454	1470

Table B.8 (a) Corrosion Monitoring Locations by Equipment and Service

The corrosion-monitoring program is further detailed in Table B.8 (b). The table shows for the active corrosion monitoring locations in Table B.8 (a), the number of coupon pulls and the number of coupons retrieved on average for each active location. It should be noted that for a typical corrosion access fitting at GPB, two corrosion coupons are recovered for each corrosion pull with the exception of those lines which are regularly pigged where single flush mounted coupons are installed.

Table B.8 (b) also shows that the weight loss coupon activity level from 1995 to year-end 2002. As discussed in prior reports, there has been a gradual reduction in the number of weight loss coupons being evaluated, which reflects the on-going effort to optimize the program to deliver maximum corrosion management information. The reducing trend in the number of corrosion weight loss coupons is also shown in Figure B.9.

The pull frequency and number of coupons per pull is summarized in Table B.8 (b). The number of coupons, the number of coupons per pull, and the pull frequency has been optimized through time to gain greater value from the data obtained from the program.

The two most significant changes are, first, the PW system pull cycle has been extended from 3 months to 6 months in order to improve the quality of the damage rate information.

Equipment	Statistic	1995	1996	1997	1998	1999	2000	2001	2002
Flow Line	Locations	204	210	203	203	202	198	199	206
	Pulls	872	880	924	850	855	820	729	776
	WLC	1610	1729	1770	1627	1674	1574	1433	1473
	WLC/Pull	1.85	1.96	1.92	1.91	1.96	1.92	1.97	1.90
	Pull/Year	4.3	4.2	4.6	4.2	4.2	4.1	3.7	3.8
Well Line	Locations	1246	1371	1427	1406	1364	1354	1255	1264
	Pulls	3361	4057	4147	3900	3685	3677	2987	2926
	WLC	6690	8130	8314	7797	7385	7364	5944	5837
	WLC/Pull	1.99	2.00	2.00	2.00	2.00	2.00	1.99	1.99
	Pull/Year	2.7	3.0	2.9	2.8	2.7	2.7	2.4	2.3

Table B.8 (b) Corrosion Monitoring Activity Statistics by Equipment Type

The second significant change was the standardization at single-operatorship of wellhead 3-phase production program to a 4-month pull cycle from a mix of 3 and 4 months as was the case previously. Both of these changes were covered in detail in prior year's reports. However, it should be noted that the effect of these extended exposure periods is a reduction in the number of coupons reported in future years.

It should be noted that the drop in the number of weight loss coupons reported for 2002 reflects the inventory of coupons that are installed in the system at year-end and are still to be 'processed.' The drop in 2002 coupon numbers therefore represents a timing effect and not a reduction in the program scope or activity level.

For the ER probes, the number of active ER probe locations in the flow lines in 2002 was 87 compared to 83 in 2001. The addition of 4 represents the addition of three new probes on the Oil system and one trial probe in the SW system.

Similar data for years prior to 2000 was not tracked and is therefore not available.

The well line ER probe-monitoring program reported in 2000 was historically used for the assessment of corrosion inhibitor performance. With the advent of single-operatorship and the revised corrosion inhibitor evaluation process, see Section D, these probes are no longer required and have been removed.

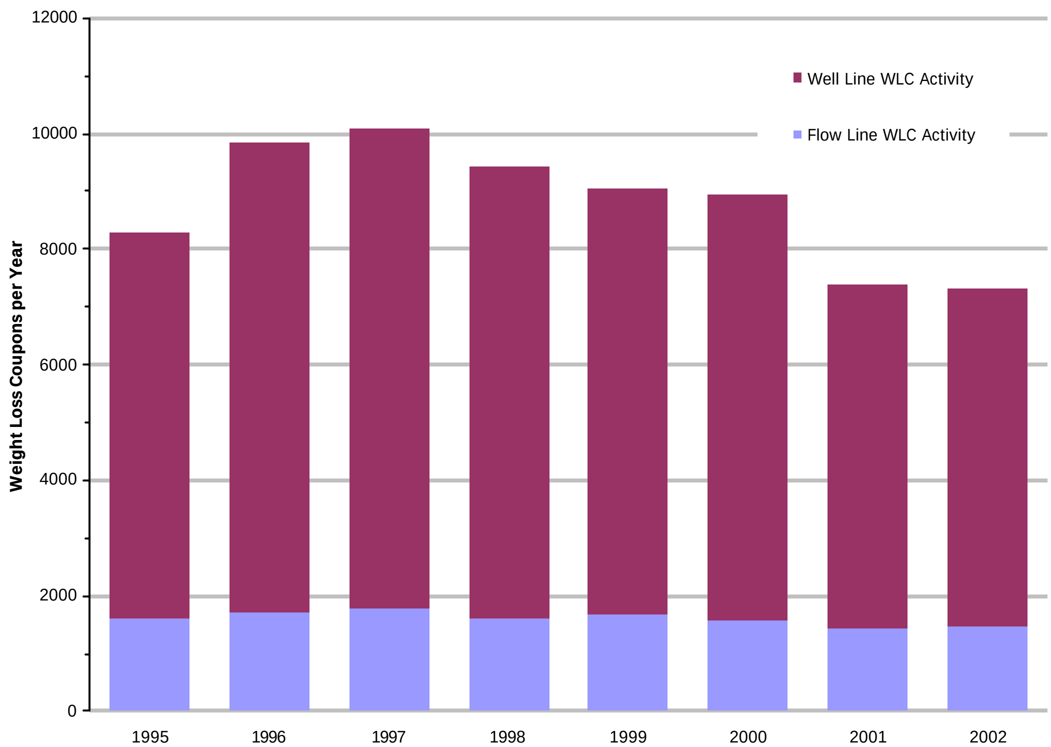

Figure B.9 Corrosion Monitoring Activity Statistics by Equipment

There is an on-going effort to optimize the corrosion-monitoring program and any future changes in pull frequency will be reported as part of the annual Charter Agreement Report.

Section B.3 Corrosion and Inspection Data Management

In order to deliver the comprehensive corrosion management program described in Section B.1, and manage the extensive corrosion monitoring and inspection activity described in Section B.2, it is necessary to have an active and structured electronic database.

Single-operatorship at Greater Prudhoe Bay (GPB) necessitated the integration of the two archaic data systems into a single unified program. This process has been an on-going effort for the last two years. Today, the weight loss coupon, inspection, electrical resistance (ER) probe and production data is held and accessed through a single database supported by Oracle© technology.

Users of the system are provided two primary methods of access to the underlying data stored in the database. The first is a custom user interface written in Microsoft Visual Basic©, and the second is through ad-hoc data query tools such as BrioQuery© and BusinessObjects© which allow free-form SQL© access to the data.

Checks for data integrity are provided at a number of different levels including error checking at the point of data capture and data entry, regular reviews of the data quality, and data rules within the database.

The data is continuously monitored for integrity and quality, and any errors are corrected as they are found. In addition, as better analysis tools become available through further integration then records are amended to reflect the improved level of analysis.

Data Record	Unit	Records	# / year	History
Weight loss coupons	10^6	0.2	0.01	~20 years
ER probes readings	10^6	0.8	0.5	~1½ years
Equipment	10^3	28	-	-
Inspection locations	10^6	0.4	.07	-
Inspection records	10^6	1.1	0.1	~10 years
Chemical injection	10^3	5	22	3 months
Production rates	10^6	7.3	0.5	~14 years
Injection rates	10^6	1.8	0.2	~11 years

Table B.10 Database Record Accumulation Rate

Table B.10 gives an illustration of the number of records and the rate at which those records are accumulated on an annual basis in the database. The table clearly shows the level of complexity involved in managing the corrosion programs at GPB.

In addition, the table also shows that the range and types of information being gathered is being improved through time to enable better overall corrosion management at the GPB. The most notable examples of this increasing range of coverage of the corrosion and inspection database is the inclusion of the production and injection data, the introduction of chemical usage data and the long term storage of ER probe data.

Table B.11 (a) Corrosion Management System					
Program	**Plan/Objectives**	**Target**	**Implementation**	**Evaluation**	**Corrective Action**
1.0 Overall program goals	• Eliminate corrosion/erosion related failures	• No harm to people • No accidents • No damage to environment	• Integrated program with monitoring, inspection, operational controls, and corrosion inhibitor	• Key performance indicators • Leading and lagging indicators	• Adjust mitigation, monitoring, and operational targets to meet objective • Defect elimination - repair/replace/abandon
	• Provide equipment availability to end of Field life	• 2050	• Integrated Program with Monitoring, Inspection, Operational Controls, and Corrosion Inhibition	• Key Performance Indicators • Leading and Lagging Indicators	• Adjust Mitigation, Monitoring, and Operational Targets to Meet Objective
	• Cost effective Corrosion Management	• Budget	• Alliance Partnerships • Incentive Contracts • Continuous Improvement	• Key Performance Indicators • Leading and Lagging Indicators	• Develop more Cost Effective Methods For Delivering the Program • Best in Class Technology • Investment for the Future

Table B.11 (b) Corrosion Management System Element – Monitoring

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.1 Corrosion Monitoring	• Monitor for changes in corrosion rates	• System dependant targets • Corrosion rate to meet overall objectives	• Short term corrosion rate determination • Medium term corrosion rate determination	• ER probes • Weight loss coupon rate • Pitting Rates	• Adjust Mitigating action to achieve corrosion rate target
	• Monitor effectiveness of the Chemical Mitigation Programs	• Optimize Corrosion Inhibitor Rates and Distribution • Optimize chemical mitigation programs e.g. o oxygen scavenger o biocide o DRA o scale	• See above	• See above	• Provide feedback to o Chemical treatment o Operations o Inspection activities • Adjust Mitigation Effort • Production Chemistry
	• Monitor Changes in the Process Conditions	• Field-wide Velocity Management targets	• Weekly Review of Operational Controls by CIC Group • Operations review of fluid velocities • Velocity alarms in DCS	• Mixture Velocities, Water Cuts, and Water Rates	• Adjust production rates to meet velocity management targets
	• Corrosion mechanism changes with time	• Mitigation action in place prior to threat to mechanical integrity	• Data availability and access • Ease of 'data mining' and evaluation • Single data storage • Comprehensive data management and reporting process	• Long-Term Process Change	• Develop mitigation program • Mechanism management as part of routine business
1.2 Erosion Monitoring	• Monitor the Effectiveness of the Erosion Mitigation Programs	• $V/V_e < 2.5$ • Max mixture Velocity and water cut matrix • Well Put-On-Production (POP) process	• Unified velocity management standard across the North Slope • Monthly compilation Of High Risk Wells • Inspection of High Risk Wells • Mixture velocity calculation in DCS	• Mixture Velocities • Inspection results	• Additional inspection and monitoring at high risk sites • Adjust Process Conditions o Well shut-in o Production reduction o Design/debottleneck facilities

Table B.11 (b) (continued) Corrosion Management System Element – Mitigation					
Program	**Plan/Objectives**	**Target**	**Implementation**	**Evaluation**	**Corrective Action**
1.3 Corrosion Mitigation	• Mitigate Corrosion Through Application of Corrosion Inhibitors	• Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	• Continuous Injection into individual wells as far upstream as possible - currently at Wellhead • Protect all equipment between injection point and separation plant	• ER Probes • WLC's • Inspection	• Corrosion Inhibitor Development • Adjust Mitigation Effort
		• Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	• Batch Treatments on a routine schedule with injection at the Wellhead	• WLC's • Inspection	• Corrosion Inhibitor Development • Adjust Mitigation Effort Through Reviews
	• Mitigate Corrosion through Operational Controls	• Operational Guidelines	• Weekly Reviews by CIC Group	• Mixture Velocities	• Adjust Process Conditions
	• Mitigate Corrosion through Maintenance Pigging	• Achieve Scheduled Frequency	• Maintenance Pigging	• Inspection • Pigging Returns	• Adjust Maintenance Pigging Schedule
1.4 Erosion Mitigation	• Mitigate Erosion Through Operational Controls and Design	• Control Erosion Rates to Acceptable Levels (See Overall Program Goals) • V/Ve < 2.5	• Well POP process • V/Ve Guidelines	• V/Ve • Inspection (ERM)	• Adjust Process Conditions

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Table B.11 (b) (continued) Corrosion Management System Element – Inspection					
Program	**Plan/Objectives**	**Target**	**Implementation**	**Evaluation**	**Corrective Action**
1.5 Inspection	• Integrated inspection program to provide a overall assessment of plant condition and corrosion rates	• Inspection activity level • Leak/save target • Inspection increases • Plant condition • Regulatory compliance	• Corrosion rate monitoring program (CRM) • Erosion rate monitoring program (ERM) • Comprehensive inspection program (CIP) • Frequent inspection program (FIP) • Corrosion under insulation program (CUI)	• NDE technique sheets and procedures • Standardized assessment of piping condition, degradation rate and mechanism	• Provide feedback to chemical mitigation program • Erosion management program • Fitness for service assessment • Equipment life assessment • Proactive repair scheduling
	• Assessment of Current Damage Mechanisms	• Zero Increases	• Internal and external programs	• See above	• Repair/replace/monitor
	• Search for New Damage Mechanisms	• Mitigation action in place prior to threat to FFS	• Baseline new equipment • Apply lessons learnt from industry practice else where in the world • Apply lessons learnt for other BP operations • Apply learnings across the field for similar equipment/process conditions • Communications with Operations and Reservoir Engineers	• See above	• Develop mitigation program • Mechanism management as part of routine business
1.6 Fitness for Service	• Fitness for service assurance	• Compliance with industry standard	• See above inspection programs	• Battelle Modified B31G fitness-for-service criteria (note piping only) • BP internal specification for the assessment of damaged pipe	• Repair equipment • Replace equipment • Derate equipment • Abandon equipment
	• Structural integrity	• Compliance with industry standard	• Walking speed survey every 5 years	• Piping design code BP Spec, B31.4 and B31.8 • Piping stress analysis • Nondestructive testing as required	• Repair/replace • Correct support defect • Monitor for further degradation

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Table B.11 (b) (continued) Corrosion Management System Element – Inspection

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.7 Continuous Improvement	• Provide Feedback to Monitoring, Mitigation, and Inspection Programs	• Continuous Improvement	• Integrated Program with Monitoring, Inspection, Operational Controls, and Corrosion Inhibitor • Provides Feedback Control Loop for Program Improvements • Consolidated data store, MIMIR	• Weekly program review • Quarterly program review • Annual program reviews and strategy assessment • Key Performance Indicators	• Strategic adjustment • Budget/funding level changes • Annual equipment life life/availability review • Mitigation process change and review • Technical/R&D requirements and programs

Table B.11 (c) Monitoring Program Techniques

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.1.1 Monitoring – Electrical Resistance Probes (ER)	• Monitor the Effectiveness of the Mitigation Programs	• < 2mpy	• ER Probes - Upstream and/or Downstream Ends of Flowlines	• Investigate Cause for Corrosion Rate Increase	• Mitigation Adjustments • ER Probe Maintenance
1.1.2 Monitoring – Weight Loss Coupons (WLC)	• Monitor the Effectiveness of the Mitigation Programs	• Gen CR: < 2mpy • Pit CR: < 20mpy	• WLC – Installed Flowlines, Well lines, Headers, and Piping	• Investigate Cause for Corrosion Rate Increase	• Mitigation Adjustments • Inspection Program Adjustments
1.1.3 Monitoring – Process Conditions	• Monitor changes in the Process Conditions	• (See Mixture Velocity and Erosion Sections Below)		• Process Upset • Long-Term Process Change	• Monitor Impact • Mitigation Adjustments
1.1.4 Monitoring – Mixture Velocity Management Program	• Monitor the Effectiveness of the Mitigation Programs	• Operational Guidelines • Mix Vel Limits	• Operations Acceptance of Mixture Velocity Guidelines • SETCIM	• Mixture Velocities • Review Alarm List to Determine True Offenders	• Adjust Process Conditions
1.1.5 Monitoring – Erosion Management Program	• Monitor the Effectiveness of the Erosion Mitigation Programs	• Operational Guidelines • Well POP • V/V_e < 2.5	• Operations Acceptance of Erosion Guidelines • High Risk Well Inspection Program (ERM)	• Monthly Reviews to Determine High Risk Equipment and Repeat Offenders	• Adjust Process Conditions

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Table B.11 (c) (continued) Mitigation Program Techniques

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.2.1 Mitigation – Corrosion Inhibitor	• Mitigate Corrosion Through Application of Corrosion Inhibitors	• Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	• Continuous Injection Into Individual Wells as Far Upstream As Possible – Currently at Wellhead • Protect All Equipment Between Injection Point and Separation Plant	• ER Probes • WLC's • Inspection	• Corrosion Inhibitor Development • Adjust Mitigation Effort
		• Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	• Batch Treatments on a Routine Schedule with Injection at the Wellhead	• WLC's • Inspection	• Corrosion Inhibitor Development • Adjust Mitigation Effort through Reviews
1.2.2 Mitigation – Operational Control, Maintenance, and Material Selection	• Mitigate Corrosion Through Operational Controls	• Operational Guidelines • Mixture Velocity Limits	• Operations Acceptance of Mixture Velocity Guidelines • SETCIM	• Mixture Velocities • Review Alarm List to determine true offenders	• Adjust Process Conditions
	• Mitigate Erosion through Operational Controls	• Operational Guidelines • Well POP • V/Ve < 2.5	• Operations Acceptance of Erosion Guidelines • High Risk Well Inspection Program (ERM)	• Monthly Reviews to Determine High Risk Equipment and Repeat Offenders	• Adjust Process Conditions
	• Mitigate Corrosion through Maintenance Pigging	• Achieve Scheduled Frequency	• Maintenance Pigging	• Inspection • Pigging Returns	• Adjust Maintenance Pigging Schedule
	• Corrosion Resistant Alloys	• Zero Increases (I's)	• Selected Facilities & Equipment	• Inspection • Applicability For Service Requirements	• Replace as Necessary
1.2.3 Mitigation – Structural Integrity	• Mitigate structural damage caused by subsidence, jacking, vibration, impact, snow loading, etc. through inspections	• No failures due to structural damage	• Operational procedures for visual surveillance of pipelines • Piping stress analysis as required • NDE inspections as required	• Pipeline Design Code/BP Specification	• Repair, replace and correct deficiencies as required • Add Pipeline Vibration Dampeners (PVDs) as required

Table B.11 (c) (continued) Inspection Program Techniques

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.3.1 Corrosion Rate Monitoring (CRM)	• Assessment of current corrosion mechanisms • Monitor for new corrosion mechanisms	• No measurable active corrosion - Zero increases (I's)	• CRM Program – Fixed locations on approximately bi-annual frequency	• Number of inspection increases	• Mitigation Adjustments • Repair/Replace Preventative Maintenance
1.3.2 Erosion Rate Monitoring (ERM)	• Monitor high risk wells • Assessment of current erosion locations	• Manageable rate of degradation	• ERM Program – monthly to quarterly	• Condition of Equipment • Rate of degradation	• Mitigation Adjustments • Repair/Replace Preventative Maintenance
1.3.3 Frequent Inspection Program (FIP)	• Assessment of High Corrosion Rates • Monitor locations near repair	• Fitness-for-Service	• FIP Program – monthly to bi-annual	• Condition of Equipment • Rate of degradation	• Mitigation Adjustments • Repair/Replace Preventative Maintenance
1.3.4 Comprehensive Integrity Program (CIP)	• Comprehensive Coverage of equipment • Fitness-for-Service review	• Fitness-for-Service	• CIP – Condition and rate based half-life recurring frequency • Extend coverage through new locations	• Condition of Equipment • Rate of degradation	• Mitigation Adjustments • Repair/Replace Preventative Maintenance
1.3.5 Corrosion Under Insulation (CUI)	• Comprehensive Coverage of equipment	• Inspection of Locations susceptible to CUI • Fitness For Service	• CUI – Risk based annual program • Management of location inventory through recurring examinations	• Damage Areas Detected • Analysis of occurrence	• Repair/Replace Preventative Maintenance

Table B.12 (a) Corrosion Monitoring Techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Corrosion Monitoring	Electrical Resistance (ER) Probes	Measurement of corrosion rate by monitoring changes in electrical resistance of a metal probe due to volume loss	High	Low	H/D	Correlate poorly to actual pipewall corrosion rates
	Weight Loss Coupons Corrosion Rate	Exposure of metal samples to corrosive fluid and calculation of volume loss rates based on weight	Medium	Medium	M	Limited benefit in determining short-term effects, such as flow regime changes on corrosion rates
	Weight Loss Coupons Pitting Rate	Exposure of metal samples and assessment of pitting rate via measurement of pit depths	Medium	Medium	M	Not a very sensitive measure for GPB 3phase but more effective in the PW system
	Galvanic Probe	Detects changes in corrosivity as a function of current flow between two dissimilar metals.	High	Low	C	Not a reliable measurement of mild steel corrosion rate. Very suitable to monitor oxygen and chlorine changes in seawater
	Linear Polarization Resistance (LPR)	Electrochemical technique for assessing corrosion rate by application of controlled voltage and measuring current response	High	Low	H/D	Not used at GPB due to the interference of hydrocarbon films on measurement

Table B.12 (b) Process Monitoring techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Process Monitoring	Mixture velocity	Mixture velocity of fluids in pipe-work	Medium	Medium	D	Accuracy dependent upon production information (T, P, Oil, Water, Gas)
	Water cut	Percent water in liquid fluids	Medium	Medium	D	Accuracy dependent upon production information (Oil, Water)
	Temperature and pressure	Measured temperature and pressure in process equipment	Medium	Medium	D	
	Dissolved Oxygen	Amount of oxygen dissolved in Sea Water	High	Medium	D	In-line accuracy problematic. Chemet method more accurate
	Iron (Fe) counts	Amount of Iron (Fe) dissolved in process water	High	Low	M	
	Microbiological activity	Amount of microbiological life forms in process fluids	Medium	Low	M	

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Table B.12 (c) Inspection/Non-Destructive Examination (NDE) Techniques – Benefits and Limitations						
Method	**Technique**	**Description**	**Sensitivity**	**Accuracy**	**Freq**	**Notes/Comments**
Inspection/NDE	Radiographic Testing (RT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through a specimen and projecting an image on conventional lead screen/film. Irregular density variations of the image can indicate metal loss.	Medium	Medium	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation. Currently being phased out in lieu of 'greener' process of DRT – see below
	Digital Radiographic Testing (DRT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through a specimen and projecting an image on phosphor screen/imaging plate. Irregular density variations of the image can indicate metal loss.	Medium	Medium	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation. DRT provides additional benefits in waste reduction associated with conventional film and processing chemicals
	Tangential Radiography Testing (TRT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through insulation at the tangent of the specimen and projecting an image on screen/film, phosphor screen/imaging plate, or detector array.	High	Low	Y	Utilized for detection of corrosion under insulation (CUI). Deployed where potential moisture ingress is suspected on thermally insulated piping
	Ultrasonic Testing (UT)	Assessment of pipe wall thickness by sending/receiving ultrasound through a specimen. Echoes returning indicate remaining thickness of the specimen.	Medium	High	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation
	Guided Wave Ultrasonic Testing (GUT)	Volumetric assessment of pipe wall by sending/receiving ultrasound through a specimen in the form of cylinder Lamb Waves. Monitoring changes in these waves indicate potential changes in pipe thickness. Alternatively, echoes returning to the source transducer may also indicate interruptions or pitting in the pipe segment.	Low	Low	Y	Utilized for cased piping assessment where access does not support use of traditional inspection methods. The method is capable of semi-quantifying metal loss but cannot discriminate between internal and external corrosion
	Electromagnetic Pulse Testing (EMT)	Assessment of pipe wall by propagating broadband electromagnetic waves on the exterior surface of the specimen. When waves traveling down steel pipe encounter corrosion on the pipe surface, the waves are distorted. Distortions in waveform may indicate rust by-product on the surface of the steel and subsequent metal loss.	High	Low	Y	Utilized for cased piping assessment where access does not support use of traditional inspection methods. The method cannot quantify metal loss and has a tendency to report false positives results but seldom overlooks surface atmospheric corrosion

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Table B.12 (c) Inspection/Non-Destructive Examination (NDE) Techniques – Benefits and Limitations						
Method	**Technique**	**Description**	**Sensitivity**	**Accuracy**	**Freq**	**Notes/Comments**
Inspection/NDE (Cont)	In-line Inspection – Smart Pig Magnetic Flux (MFL) Technique	Assessment of pipelines for the detection and measurement of metal loss. These pigs carry high strength magnets, which apply a strong magnetic field into the pipe wall. The magnetic field saturates the pipe steel with magnetic flux. As a result, areas of metal loss cause the flux to leak out of the pipe wall. The flux leakage data is recorded and used to infer the size and depth of any metal loss defects in the pipe.	High	Medium	N/A	Utilized where design and process operation permit in-line pigging. Metal loss MFL In-line Inspection provides complete evaluation of pipeline integrity within the limitations of the MFL technique.

Table B.13 Corrosion Management System Implementation by Equip Type and Service				
Service	**Equipment Type**	**Monitoring Technique**	**Inspection Program**	**Mitigation Program**
Oil	Flow line	▪ ER Probes ▪ WLC ▪ Process Monitoring	▪ CRM ▪ FIP ▪ CIP ▪ CUI	▪ CI Injection ▪ Mixture Velocities ▪ Periodic Maintenance Pigging ▪ Operational Controls
	Well line	▪ WLC ▪ Process Monitoring	▪ CRM ▪ ERM ▪ FIP ▪ CIP ▪ CUI	▪ CI Injection ▪ Mixture Velocities ▪ Mixture Velocities ▪ Operational Controls
Produced Water	Flow line	▪ WLC	▪ CRM ▪ FIP ▪ CIP ▪ CUI	▪ CI Injection* ▪ CI Carry Over ▪ Periodic Maintenance Pigging ▪ Mixture Velocities ▪ Operational Controls
	Well line	▪ WLC	▪ CRM ▪ FIP ▪ CIP ▪ CUI	▪ CI Injection* ▪ CI Carry Over ▪ Mixture Velocities ▪ Operational Controls
Seawater	Flow line	▪ WLC ▪ Galvanic Probes ▪ Dissolved 0_2 ▪ Microbiological Activity	▪ CRM ▪ FIP ▪ CIP ▪ CUI	▪ Biocide Treatment ▪ 0_2 Scavenger ▪ Periodic Maintenance Pigging ▪ Operational Controls
	Well line	▪ WLC ▪ Microbiological Activity	▪ CRM ▪ FIP ▪ CIP ▪ CUI	▪ Biocide Treatment ▪ Periodic Maintenance Pigging ▪ Operational Controls
Export oil	Flow line	▪ WLC ▪ ER Probes	▪ CRM ▪ FIP ▪ CIP ▪ CUI	▪ CI Carry Over ▪ Mixture Velocities ▪ Operational Controls ▪ Periodic Maintenance Pigging

* No CI injection for FS-2 PW

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Section C

Weight Loss Coupons and Probes

Section C Weight Loss Coupons and Probes

This section summarizes the results of the weight loss coupon corrosion-monitoring and ER probe program. Each of the major service categories is reviewed in turn with the results of the program discussed along with major conclusions and significant recommendations.

Detailed data tables for each configuration of equipment type, flow line and well line, and each service category, 3-phase, produced water and seawater, are provided in the Appendix 5 – Data Tables.

Section C.1 Three Phase (OWG) Production Systems

The corrosion mechanism of concern in the 3-phase production system is CO_2 corrosion, in which CO_2 from the produced fluids dissolves and dissociates in the produced water to form an acidic environment that is, if untreated, corrosive to carbon steel[5,6]. The primary corrosion control method is the continuous addition of corrosion inhibitor in the flow lines and a mix of continuous and batch inhibitor additions in the well lines.

For the 3-phase production system the target corrosion rate from weight loss coupons is 2 mpy or less for general corrosion rate and 20 mpy for the pitting rate.

Figure C.1 shows the average corrosion rate and percentage of coupons meeting the performance standard of ≤2 mpy over the last 10 years for the cross-country flow lines. The results show that the corrosion rate and percentage of conformant flow lines has improved consistently over the last decade such that now the average corrosion rate across GPB is approximately a factor of 10 lower than the corrosion rates from the early 1990's.

The reduction in corrosion rate by a factor of 10 over the last decade is a direct result of the implementation of an aggressive corrosion mitigation program consisting primarily of continuous addition of corrosion inhibitor into the production fluids. This program has been implemented at considerable capital and operating expense but has resulted in flow lines which are now expected to be fit-for-service (FFS) for approximately 10 times as long as that expected in the early 1990's due to the reduction in corrosion rate.

Figure C.2 shows the correlation between average corrosion rate, mpy, and the percentage of weight loss coupons meeting the 2 mpy target. As might be

[5] Corrosion Control in Petroleum Production, Harry G Byers, NACE, 1999
[6] Corrosion Control in Oil and Gas Production, Treseder and Tuttle, NACE, 1998

expected, there is a very strong correlation between these two metrics. However these two metrics should be viewed as being complementary. The percentage less than 2 mpy target has the advantage of highlighting non-conformances that would otherwise be lost in the calculation of the average.

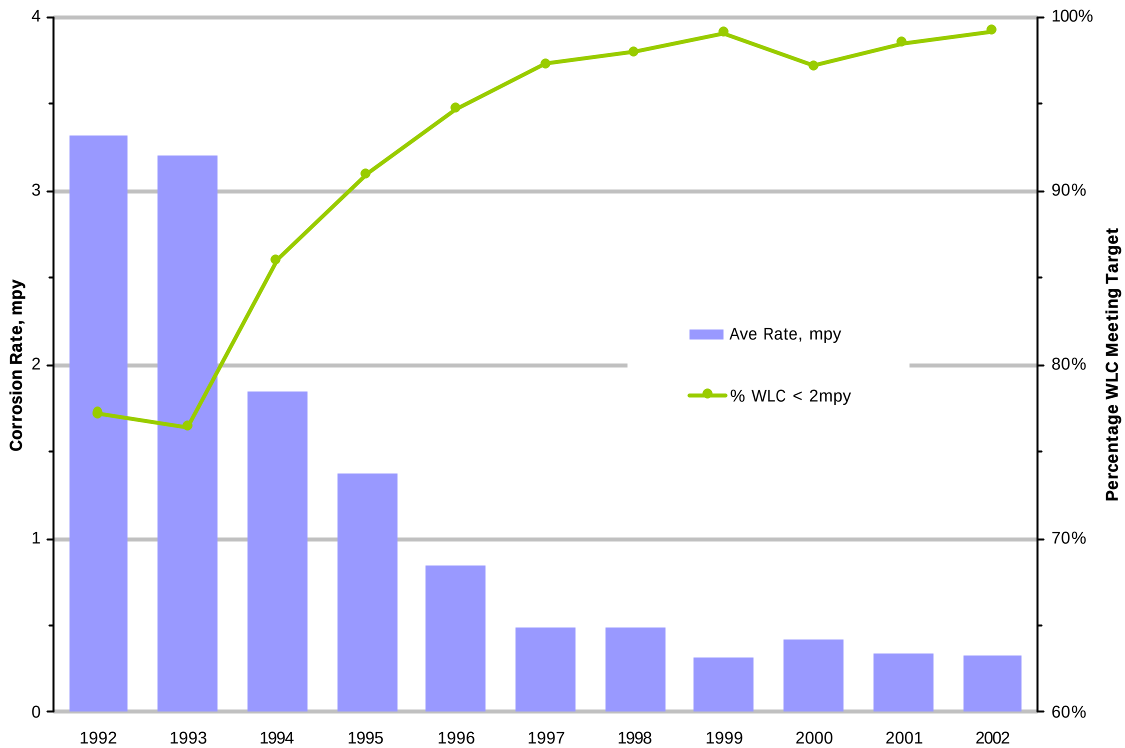

Figure C.1 Flow Line Corrosion Rate Trend 1992 to 2002

Conversely, the average has the advantage of showing the overall performance trend that might otherwise be lost when only looking at the exceptions > 2 mpy. Hence, it is necessary to review both metrics in order to gain an overall understanding of the performance of the program.

Figure C.3 shows the same data set for the well lines in oil service. The trends are very similar to those seen in the cross-country flow lines. The well lines show a long-term improvement in the level of control from early 1990's to the present day. In the short term there has been a reversal in the trend of increased corrosion rates seen between 1999 and 2000 with the corrosion rates falling in both 2001 and again in 2002.

The long term corrosion control improvement in the well lines is of the same magnitude as that seen in the flow lines with corrosion rates being reduced from an average of 3-4 mpy in 1992/3 down to an average of ~0.6 mpy for 2002.

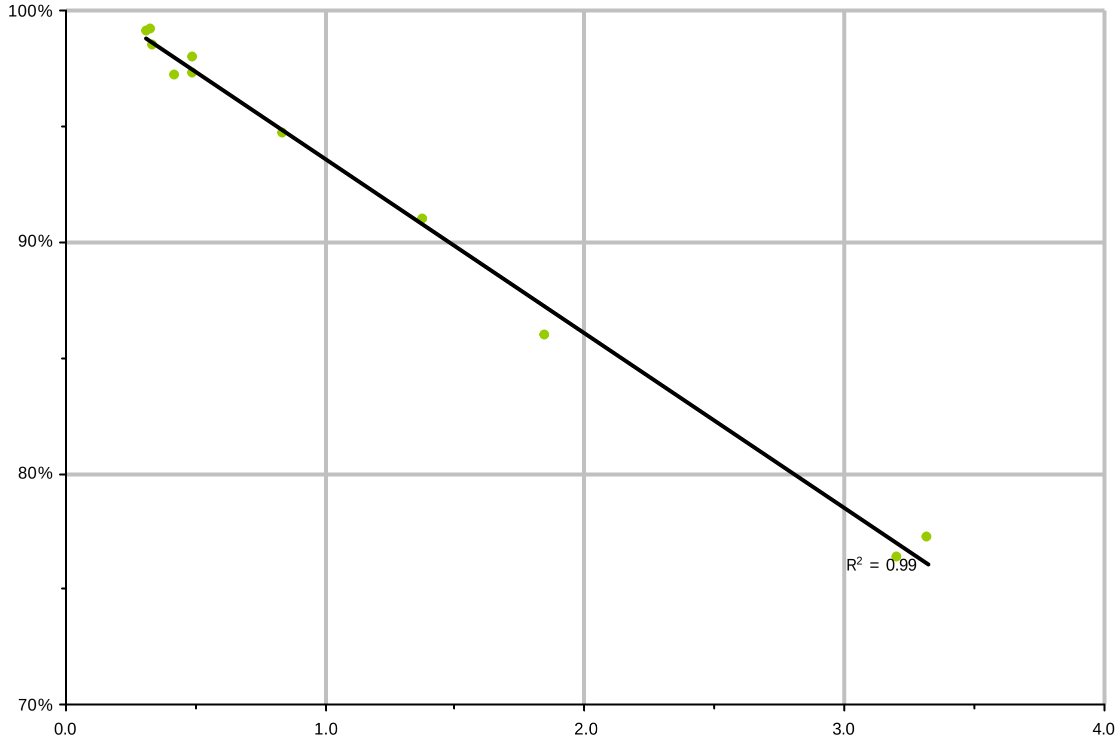

Figure C.2 Correlation Between Flow Line Corrosion Rate and Percentage Conformance

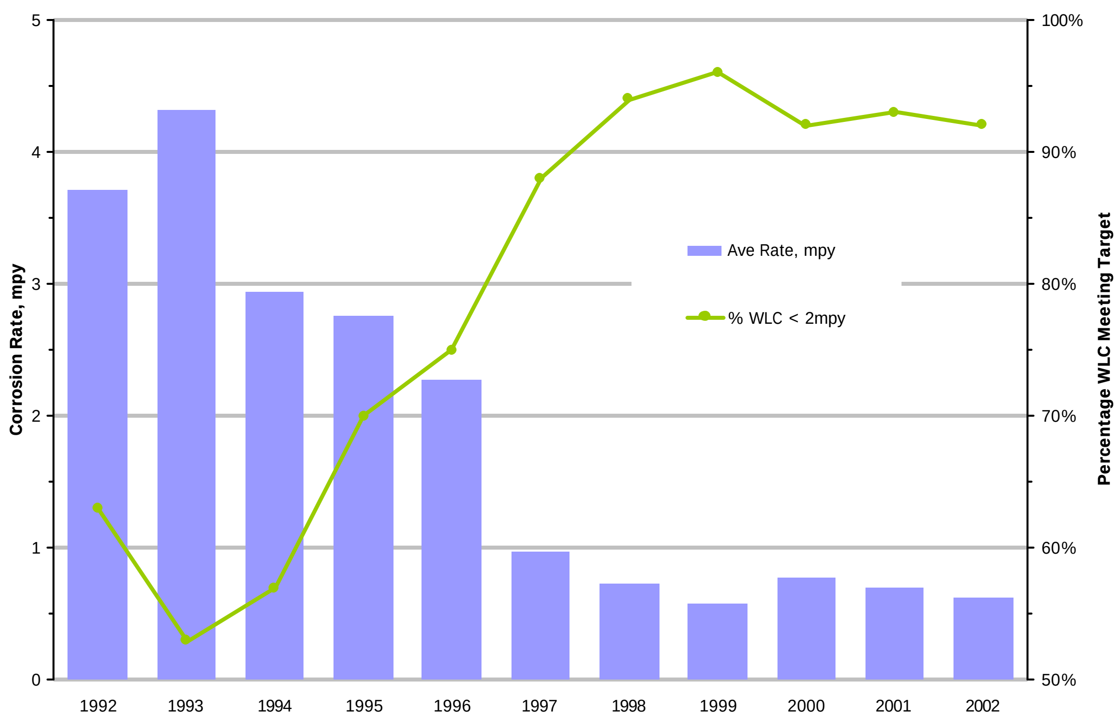

Figure C.3 Well Line Oil Service Corrosion Rate Trend 1992 to 2002

In summary, the 3-phase production system has seen a strong improvement in corrosion control since the early 1990's with a near order of magnitude reduction in the cross-country flow line corrosion rates. This same trend is also seen in the inspection history as discussed in a Section E. The decrease in corrosion rate in the 3-phase systems is attributable to the implementation of an aggressive corrosion inhibition program. A similar trend in performance improvement is seen in the well lines. However, the ultimate performance is not as good as the flow lines but still considerably below the 2 mpy target rate.

The correlation between corrosion inhibitor injection rates and concentration, and the corrosion rates in the flow lines is discussion in detail in Section D.

Section C.2 Water Injection Systems

The Water Injection System at GPB is comprised of produce water from the primary processing/separation facilities and seawater extracted from the Beaufort Sea through the Seawater Treatment Plant (STP).

In 2002 the production database was linked to the corrosion and inspection database. This dynamic link provides a much more detailed view of service history/changes for the well line equipment enabling an improved level of data analysis and quality. As a result of this enhanced ability to analyze the wellhead coupon and injection information, the data-reporting format in the 2002 report has changed from that given in prior years.

For operational reasons such as reservoir injection conformance management, operational availability of water and miscible injectant, and the water-alternating-gas (WAG) schedule for secondary recovery, the fluids being injected at a given wellhead change frequently. As a consequence when reporting the fluid which any given weight loss coupon is exposed to is not always as simple as reporting the injection service at coupon installation or removal. Historically, the service code reported has been a single value, however, with the dynamic linking of the weight loss coupon data and the actual injection history it is possible to report composite services for a coupon exposure period.

Table C.4 summarizes the number of coupons in the injection system over the last 5 years, 1998-2002, and shows how a significant portion of those coupons were exposed to multiple changes in injection service during the exposure period.

From the table it can be seen that ~60% of the injection service weight loss coupons have seen single service during the exposure period and ~40% have seen multiple services. The principle injection fluids are seawater (SW), produced water (PW), and miscible injectant (MI). If the analysis is expanded from 100% single service to a simple majority description then the amount of data included in the analysis increases. However, it should be noted that even as a simple plurality, only ~85% of the injection service weight loss coupons are included in the analysis of water injection system corrosion rates.

As a consequence of the dynamic linking of the weight loss coupon history to the injection and production data, the totals in Section C will not match the activity totals in Section B which are reported independent of the injection or production service.

Statistic	WLC	%	Statistic	WLC	%
100% SW service	237	5%	Majority SW service	293	7%
100% PW service	2458	56%	Majority PW service	3443	79%
100% MI service	183	4%	Majority MI service	575	13%
Other	1491	38%	Other	58	1%
Total	**4369**	**100%**	**Total**	**4369**	**100%**

Table C.4 Summary of Coupons in Injection Service

In summary, the new reporting format that augments the performance metrics and was agreed with ADEC can be summarized as follows,

Report Date Mid point of the WLC's exposure period,

$$\text{Mid Date} = \text{Date In} + \frac{(\text{Date Out} - \text{Date In})}{2}$$

Service Type (a) Ave corrosion Rate with 100% exposure to service

(b) Ave Corrosion Rate with simple service majority

Full data sets are included in the data tables in Appendix 5.

Section C.3 Water Injection System Main Distribution Lines

Figure C.5 is a summary of flowline data for produced water and seawater reported in aggregate. The data shows that the 2002 corrosion rates in the flow lines have increased but are in general still below the 2 mpy criteria, ~90% less than 2 mpy. The increase in rate is largely due to activity in the seawater system discussed in Section C.5.

The period, 1993-1996, of increased in corrosion rate is the last time there were significant issues within the SW system. Although there are on-going issues in the SW system, see Section C.5, SW service flow lines now constitute a lower percentage of the overall injection service system and therefore have a less significant impact on the aggregate flow line statistics presented in this report.

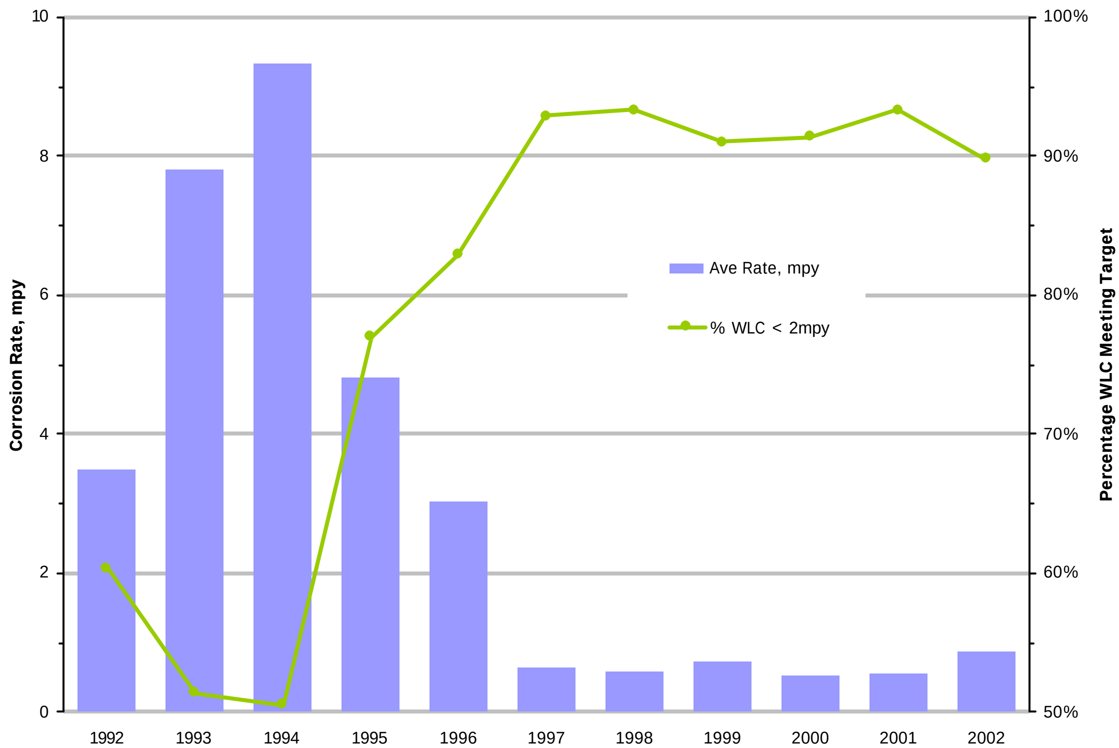

Figure C.5 Flow Line PW/SW Service Corrosion Rate Trend 1992 to 2002

In summary, the average internal corrosion rates for the aggregate water injection service have risen slightly in 2002 when compared with the average for the prior 5 years. As the average corrosion rate has risen so the number meeting the corrosion rate target of 2 mpy has fallen from 93% in 2001 to 90% in 2002. The primary cause of this deterioration in corrosion control is attributed to the problems encountered in the seawater system that is discussed in detail later in Section C.5.

Section C.4 Produced Water Injection Systems

There are a number of corrosion mechanisms of concern in the produced water section of the injection system. These mechanisms include CO_2 corrosion and differential concentration effects due to the high particulate content of the system. The particulates consist primarily of residual hydrocarbon remaining after oil, water, gas separation, production chemicals, and iron sulfide.

Figure C.6 (a)-(e) summarize the historical corrosion rate data for produced water well lines through year-end 2002. The data shows that the general corrosion rates in the produced water system have fallen as the level of inhibition in the 3-phase system has increased and supplemental produced water injection systems have been initiated.

The trend for 100% produced water service is summarized in Figure C.6 (a). For 2002 the average corrosion rate in the well lines in produced water service was 0.3 mpy with 97% of the well lines falling below the target corrosion rate of 2 mpy.

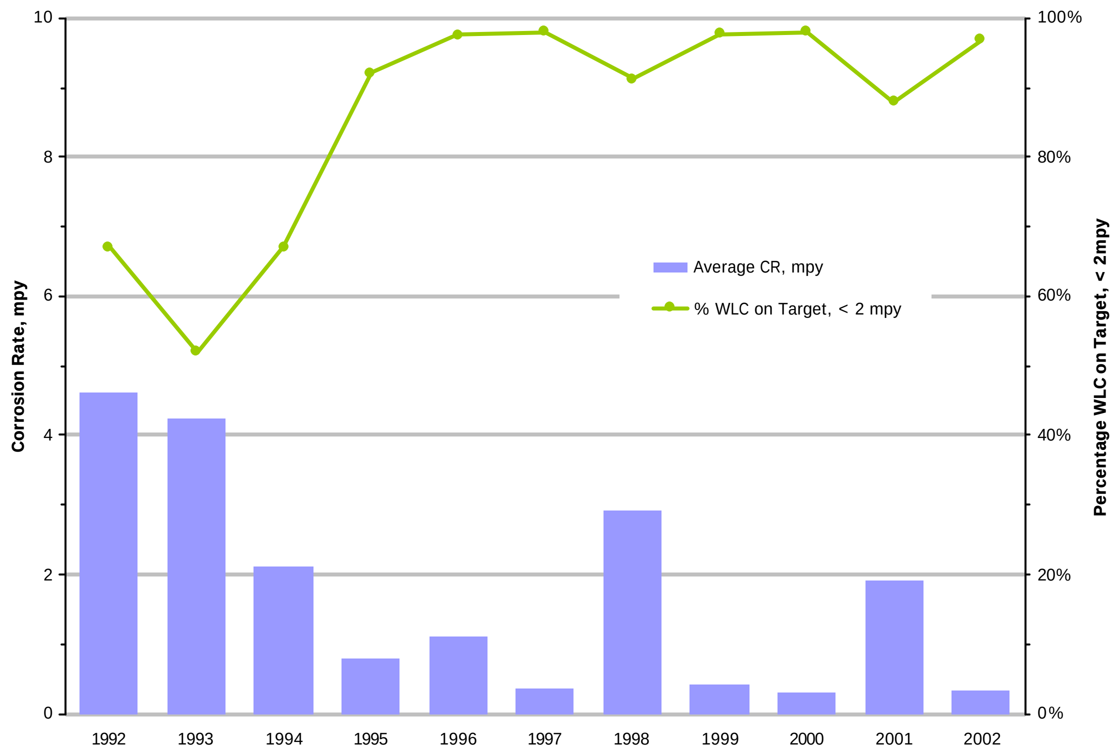

Figure C.6 (a) Corrosion Rates for 100% PW System 1995 to 2002

For those coupons where the produced water was the majority service, Figure C.6 (b) shows that the corrosion rate trends were very similar to that seen for 100% produced water service. The average corrosion rate for 2002 was 0.3 mpy and approximately 96% of the coupons met the corrosion control target of 2 mpy.

A comparison of the corrosion rate trends for produced water between the 100% service and majority service is provided in Figure C.6 (c). The figure shows there is little or no difference between the two trends.

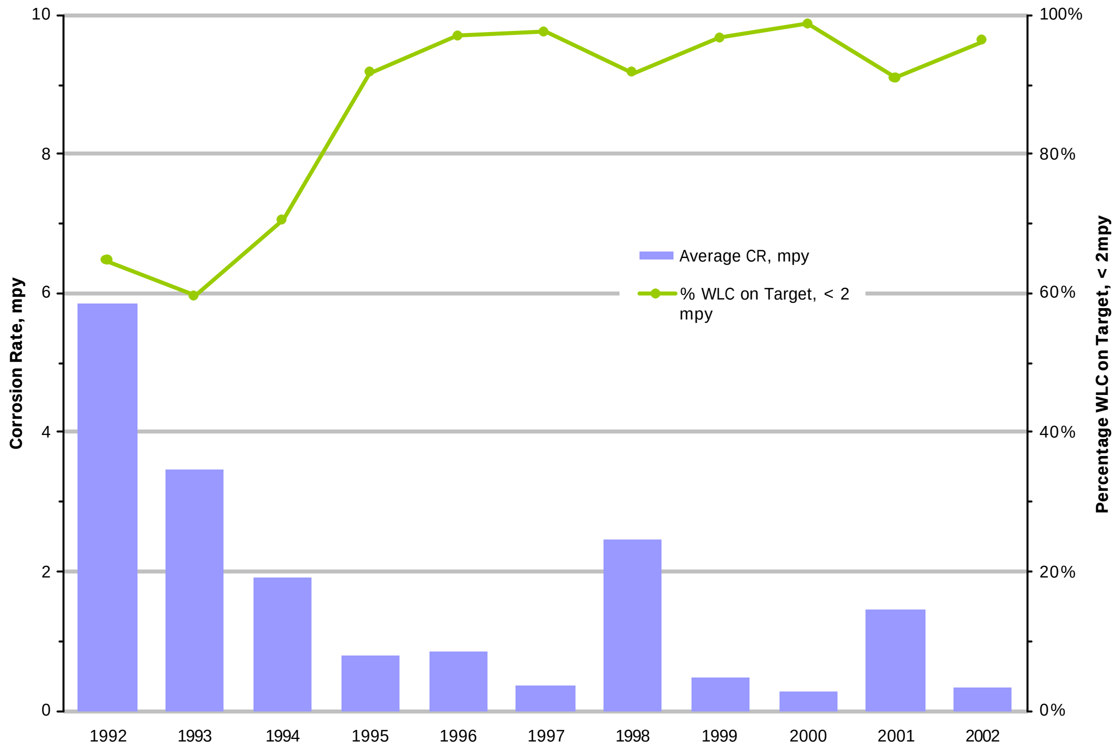

Figure C.6 (b) Corrosion Rates for Majority PW System 1992 to 2002

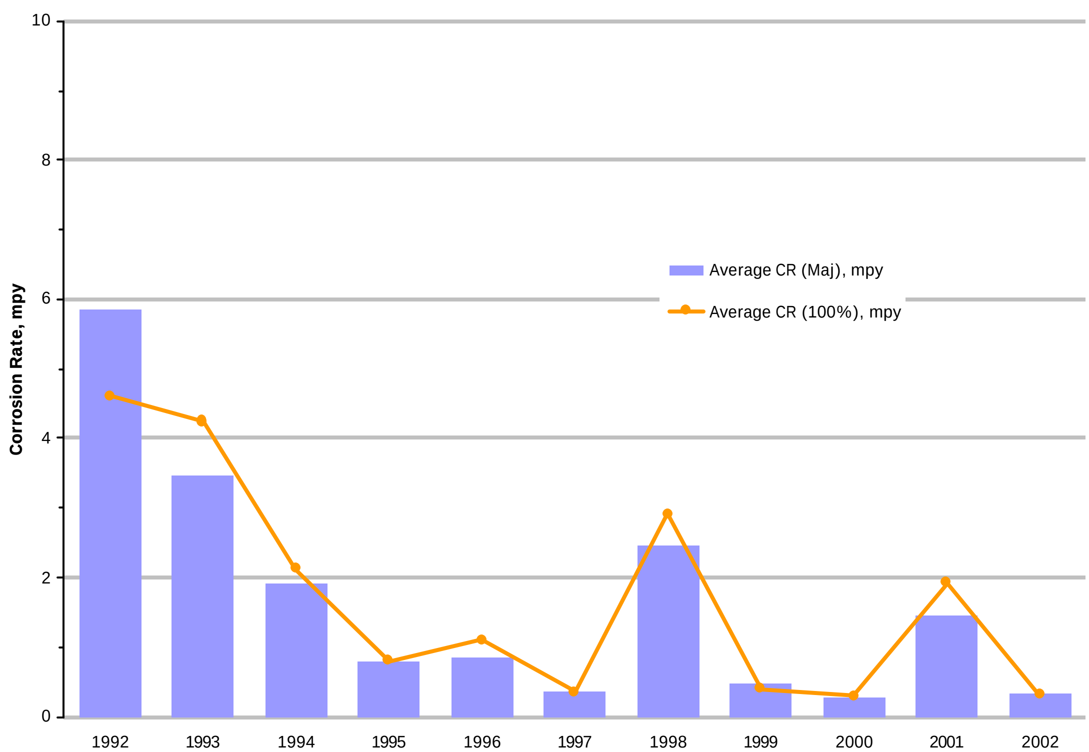

Figure C.6 (c) Comparison of Corrosion Rates for 100% and Majority PW System 1992 to 2002

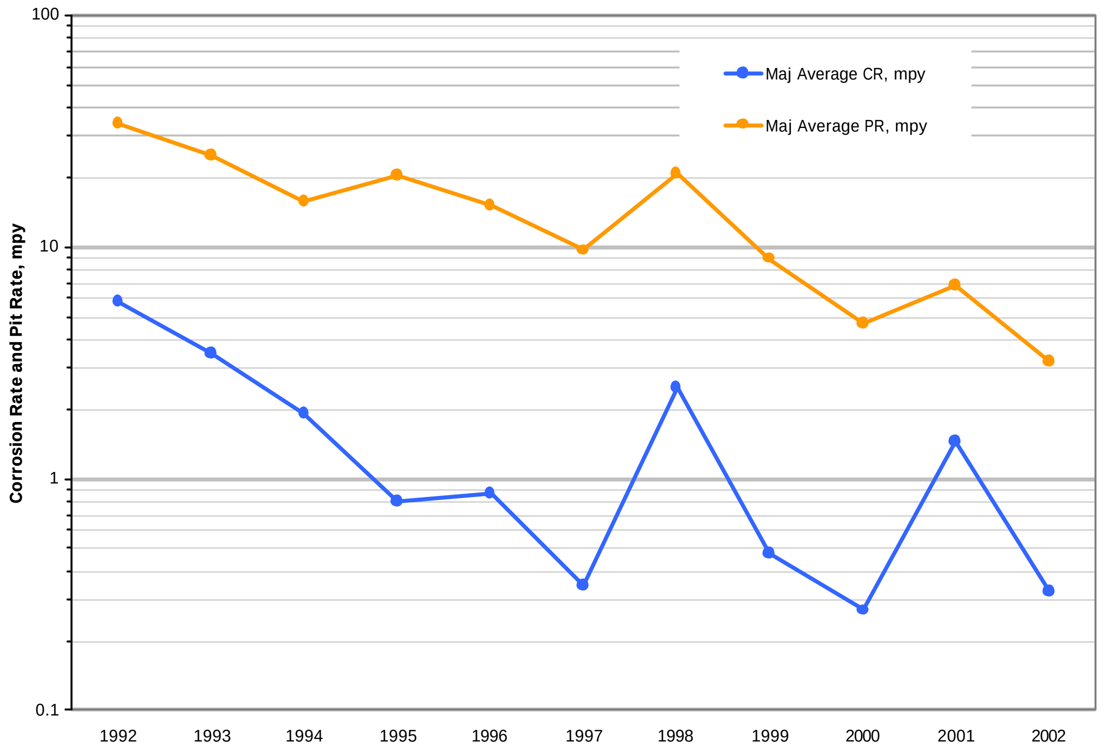

Figure C.6 (d) Corrosion Rates and Pitting Rates for Majority PW System 1992 to 2002

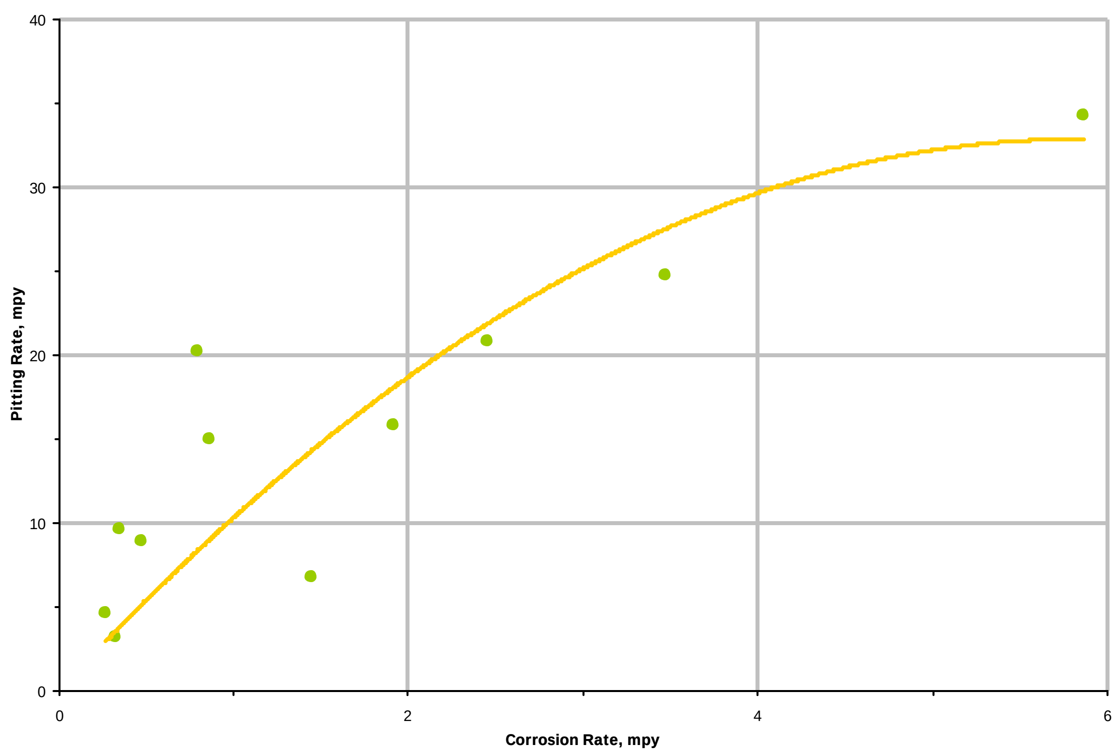

Figure C.6 (e) Correlation Between Corrosion Rates and Pitting Rates for Majority PW System

Figure C.6 (d) and (e) are a comparison between the general corrosion rate and the pitting rates for the produced water system. From both figures it is clear that there is a correlation between the two trends with the pitting rate being approximately 10-fold higher than the general corrosion rate.

The overall improvement in the performance of the PW system can be attributed primarily to two factors. First, there was a change in the upstream 3-phase production continuous corrosion inhibitor in 2002 that gave more favorable partitioning characteristics to the water phase than the prior product. This had the effect of increasing the levels of corrosion inhibitor carried from the upstream system into the produced water distribution network. The second contributor was the implementation of corrosion mitigation programs specific to the PW system through 2002 with the program being expanded to include PW systems at FS-1 and FS-3 in addition to the existing program at GC-1, GC-2 and GC-3.

Section C.5 Seawater Injection System

The main corrosion mechanisms in the seawater (SW) injection systems are,

- Dissolved oxygen (DO) corrosion is mitigated by processing the seawater to remove oxygen. Initial DO removal is achieved mechanically by vacuum stripping which is then followed by chemical oxygen scavenging
- Microbiological corrosion, due to the action of anaerobic bacteria, is mitigated by batch treatment with biocide, after processing to remove O_2, and prior to transfer to the main cross country flow lines

As with the PW system, the SW system data are presented as both 100% and majority service for the well line data, along with a comparison of general corrosion rates and pitting corrosion rates.

Figures C.7 (a)-(e) shows the corrosion rate trends in the SW system. In all cases, 100% SW service, majority SW service, and both pitting and general corrosion rates, the corrosion rates are seen to be increasing from 2000 through 2002.

As a consequence of the increasing corrosion rate trends in the seawater system, and as discussed in the 2001, and again at the 2nd 2002 Meet and Confer session with ADEC, a number of corrective actions have been taken to reverse this trend.

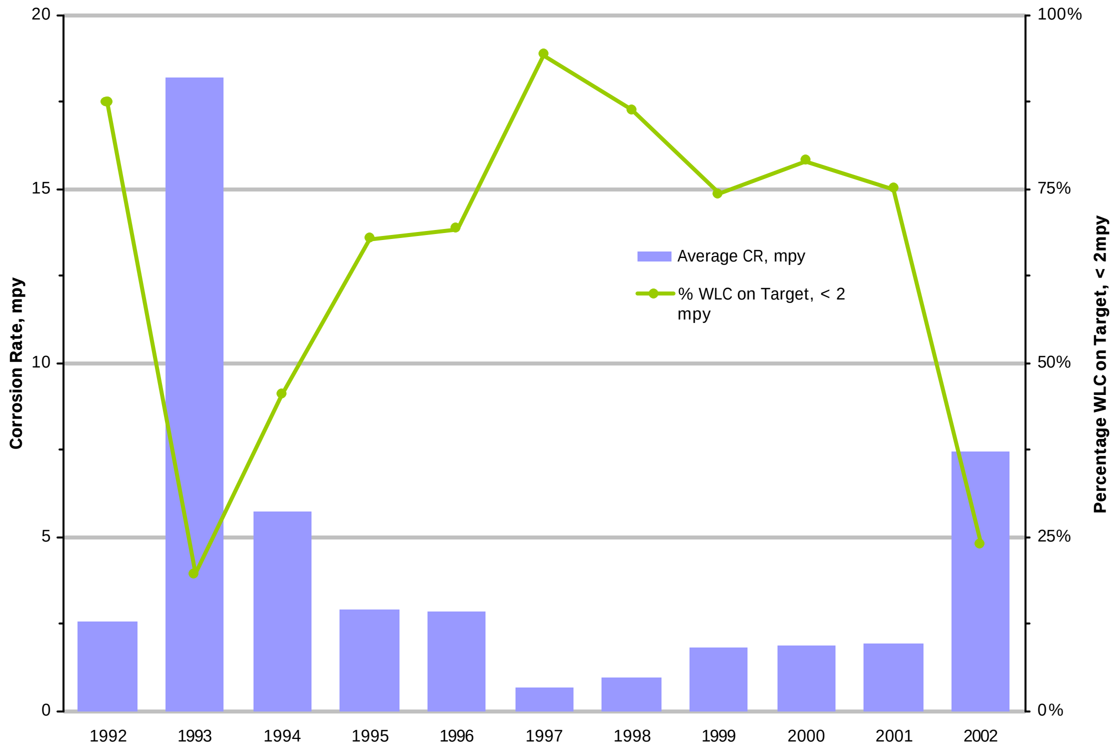

Figure C.7 (a) Corrosion Rate for 100% Seawater System 1992 to 2002

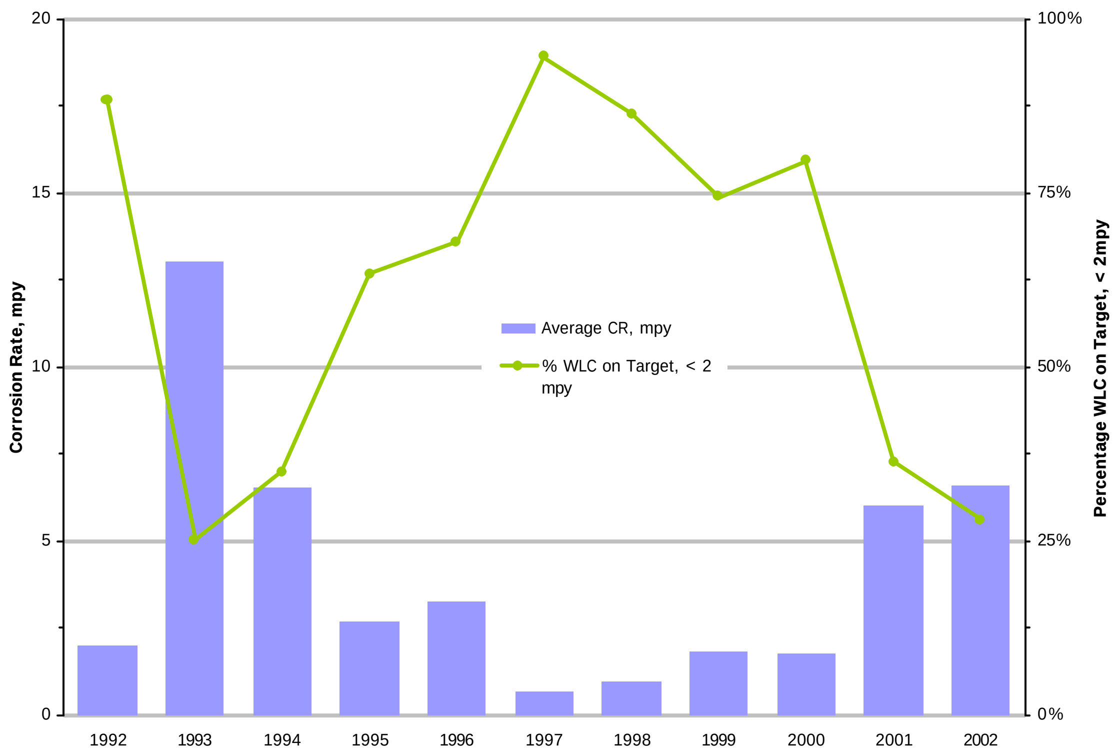

Figure 7.6 (b) Corrosion Rates for Majority SW System 1992 to 2002

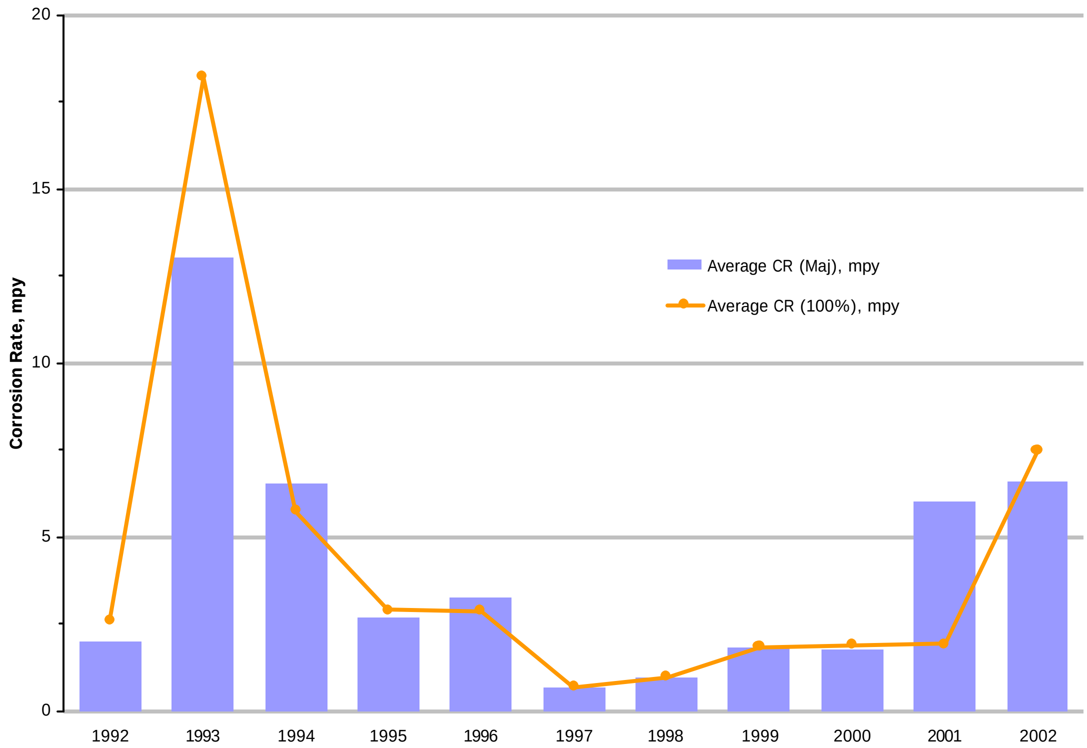

Figure C.7 (c) Comparison of Corrosion Rates for 100% and Majority SW System 1992 to 2002

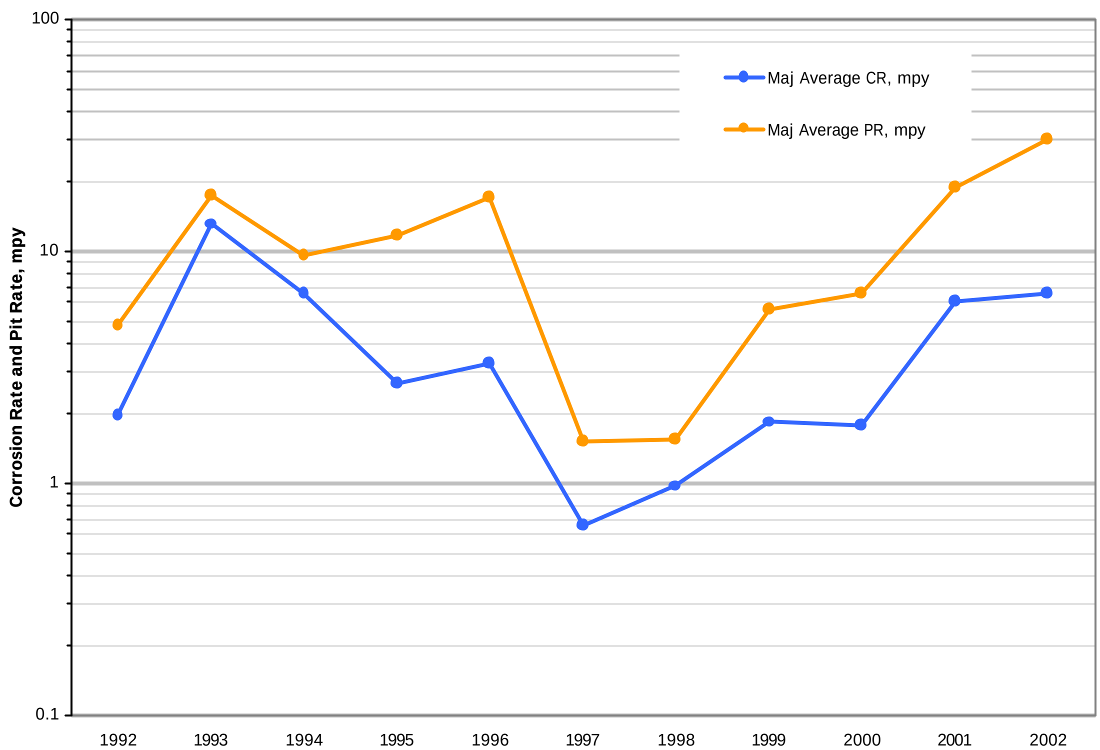

Figure C.7 (d) Correlation Between Corrosion Rates and Pitting Rates for Majority SW System

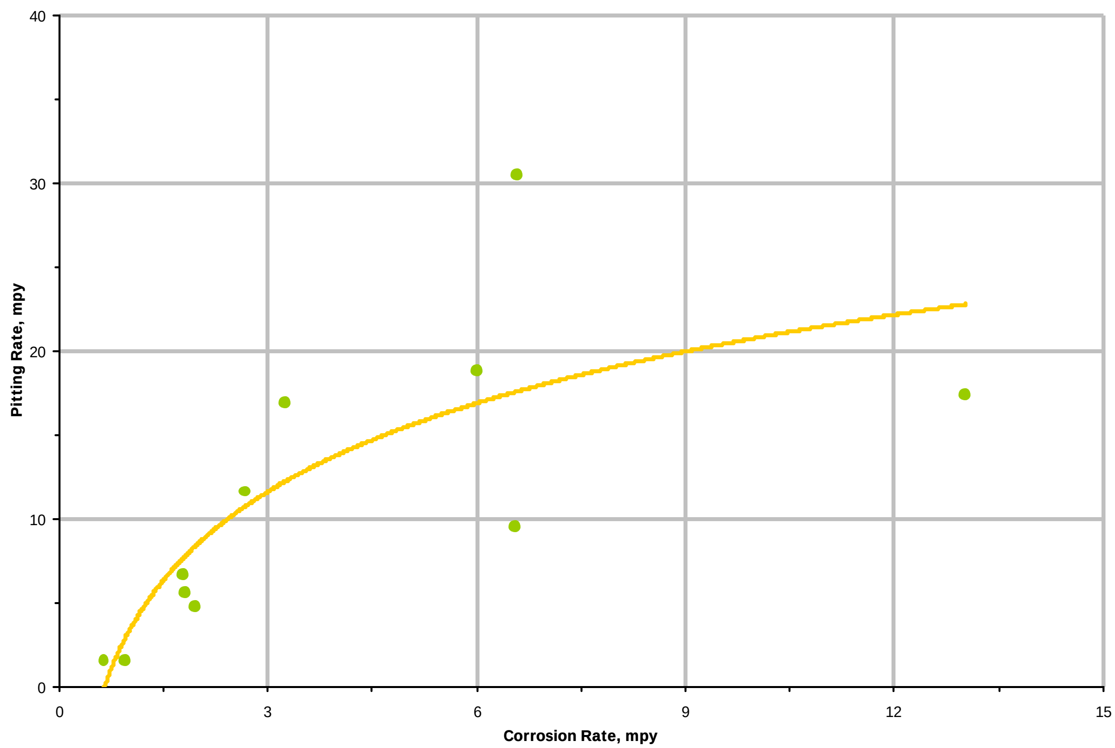

Figure C.7 (e) Correlation Between Corrosion Rates and Pitting Rates for Majority SW System

Unfortunately, while the corrosion mitigation improvements have been put in-place in 2002, the Seawater Treatment Plant (STP) and the downstream distribution system were shut-in for a substantial portion of the year. The seawater system is being rehabilitated and upgraded to provide additional water injection capacity for the future. The lack of steady state conditions through the year has complicated the evaluation of the corrective actions established in 2002 and it is at this time unclear whether or not these actions have been successful.

The determination of the effectiveness of the mitigation changes in 2002 and whether or not additional corrective action is required will continue to be a major focus for 2003 as a sustained and long term supply of seawater is required for optimal water flood/oil recovery and reservoir pressure support.

The most significant of the corrective actions are summarized below. To achieve corrosion control in the SW system, a combination of microbiological and oxygen control is required. Problems with oxygen control in the system were addressed in 2001 and 2002. The following targets, controls and corrective actions reduced oxygen in the seawater,

- Residual dissolved oxygen (DO) target was set to < 20 ppb (parts per billion) after vacuum deaeration and chemical oxygen scavenging

- The DO meter was upgraded and meter maintenance and calibration frequency were increased
- Antifoam was added to the vacuum towers to improve the performance and hence reduce DO levels leaving the tower
- Extensive plant repair and maintenance in preparation for SW volume ramp-up

Despite the non-steady state operation of STP throughout 2002, it is believed that the improved oxygen control has decreased corrosion in the upstream portion of the SW system, but corrosion continued to increase in the downstream parts of the system. The preliminary data suggests that there is an improved level of corrosion control in the upstream portion of the system as shown in Table C.8, which shows the percentage of inspection results that are showing increases. The inspection data for 2000, 2001, and 2002 has been divided into 2 groups, upstream which is that portion of the SW injection system immediately downstream of STP, and the downstream which is main in-field distribution lines.

	2000	2001	2002
Upstream Flow Lines	8%	0%	1%
Downstream Flow Lines	26%	8%	22%

Table C.8 Inspection Increases for the SW System

Figure C.9 shows the daily and weekly average level of dissolved oxygen control in the seawater system through 2002. The figure shows that there were 6 occasions when the weekly average DO level exceeded the 20 ppb billion target. Of these six occurrences, 4 occurred in 1Q 2002 with just a single incident in 2Q, none in 3Q, and 1 in 4Q. Clearly the actions taken to address the performance of the dissolved oxygen content of the processed seawater leaving STP have resulted in a significant level of conformance to target in 2002.

High corrosion rates were expected in 2002 due to long periods of shut-in while the system was upgraded to achieve higher seawater rates. However, the seawater system has been, and continues to be, a main focus of concern. The following actions were taken to improve microbiological control of the seawater system despite the complications associated with the periods of shut-in due to the system upgrade,

- Maintenance pigging frequency has been doubled along with an improved disc/brush pig design
- Biocide treatment frequency was doubled, from once every 2 weeks to once a week

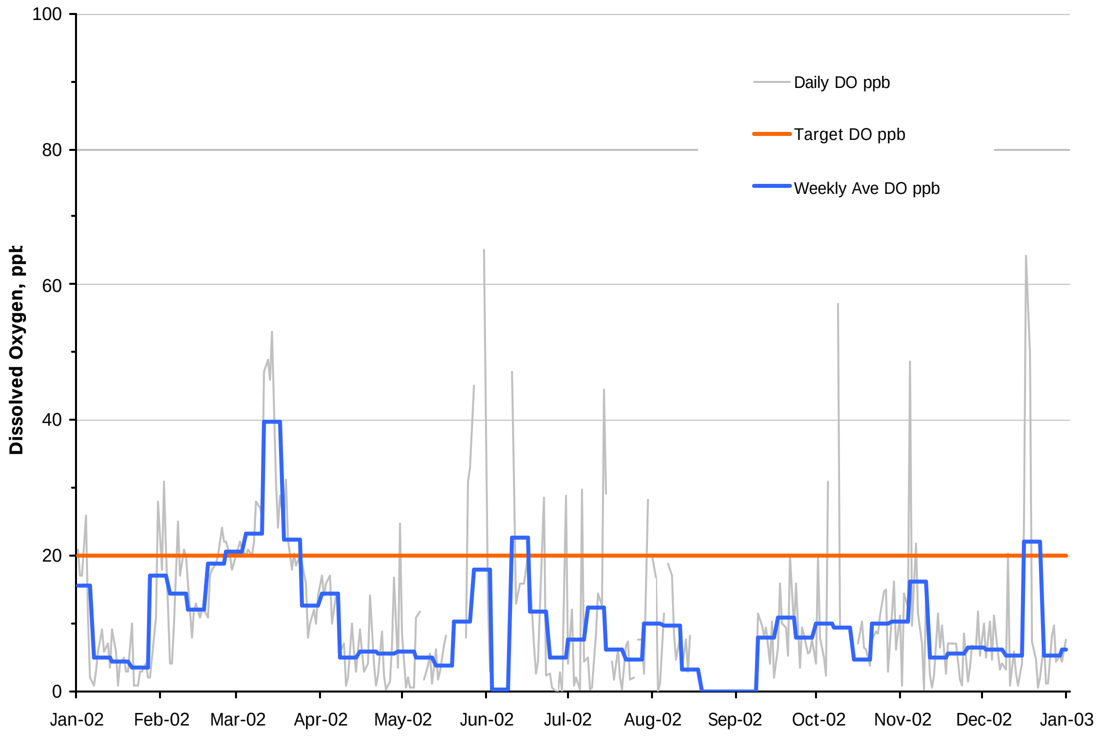

Figure C.9 Dissolved Oxygen Control Performance for the Seawater System 2002

- The microbial monitoring program was reconsidered and improved. Microbial monitoring is done monthly
- A biocide soak of the entire system was done at high biocide concentration during system shut-in
- Measurement of biocide residuals was implemented and used to track biocide concentrations through the system
- Biocide treatment regimes were modeled, and various treatments are being tested for efficacy in delivering biocide at effective concentrations to the downstream parts of the system
- Technical support was solicited and received from biocide supplier in guiding reconsideration of the biocide treatment program
- The corrosion-monitoring program in the main seawater supply line was changed to increase the pull frequency of weight loss coupons from annual to quarterly, effective at the end of 2001

Table C.10 summarizes the changes in the biocide treatment regime for the SW system and Figure C.11 shows the corresponding effective weekly concentration of biocide as ppm against the quarterly average corrosion rate for the well head coupons with a majority service of SW.

From	To	ppm	Interval	Product
Jan-97	Jul-97	750	7	Glutaraldehyde
Jul-97	Feb-00	750	14	Glutaraldehyde
Feb-00	Aug-01	450	14	Glutaraldehyde/quaternary amine blend
Aug-01	Jul-02	500	14	Glutaraldehyde/quaternary amine blend
Jul-02	Dec-02	500	7	Glutaraldehyde/quaternary amine blend
Dec-02	Mar-03	500	7	Glutaraldehyde/quaternary amine blend
Mar-03	Present	750	7	Glutaraldehyde/quaternary amine blend

Table C.10 Biocide Treatment Concentration and Interval

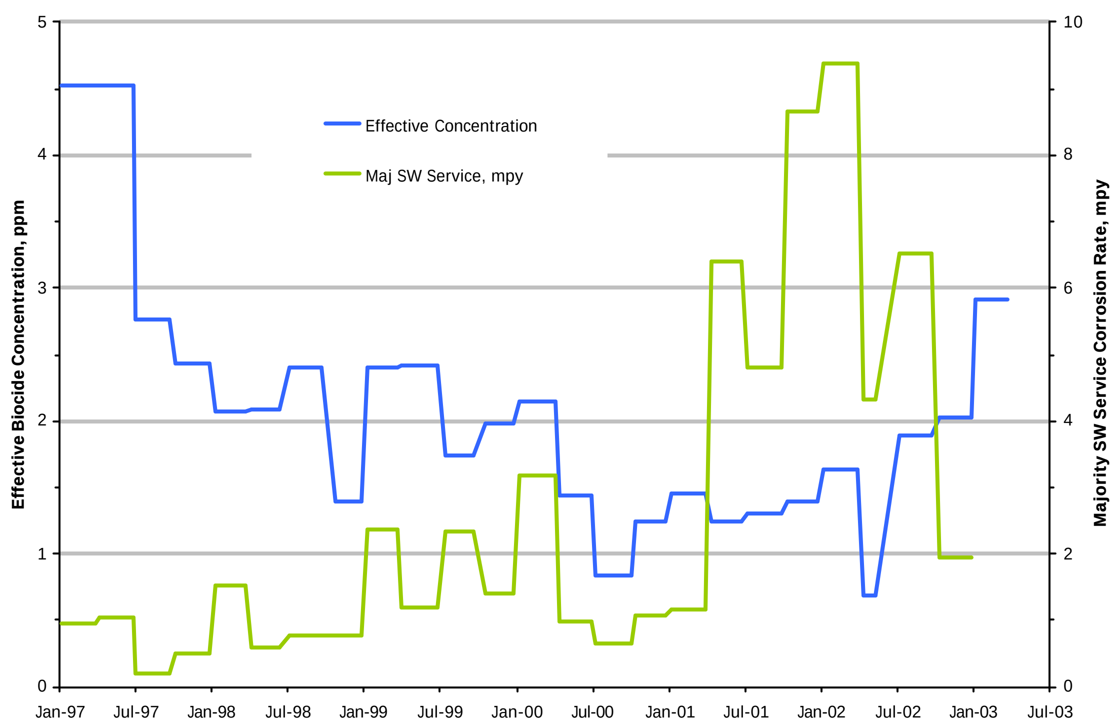

Figure C.11 Biocide Treatment Concentration and Corrosion Rate

While Figure C.11 contains only preliminary information, and no long-term trend has been established, the data does suggest that the increase in biocide additions and the changes in the biocide treatment regime are beginning to have an impact. The data for the second half of 2002 at least shows that the problem is getting no worse and potentially indicates that corrosion rates are declining if not yet at or below target rate. Clearly this data is still preliminary and continued effort will be required in 2003 to assure that full control of the seawater system has been established and implementation of the long-term treatment regime.

In summary, a number of changes have been made in 2002 to the treatment rates and targets within the seawater injection system to rectify problems that were identified in prior years. The preliminary data suggest that these changes have been effective with the inspection program showing a reduction in corrosion activity level in the upstream pipe work and the weight loss coupon program suggesting progress in reversing the corrosion trends at the extremities of the seawater distribution system. Although the initial data suggests that progress has been made in returning the seawater system to control, there will be an on-gong effort in 2003 to assure that this trend is confirmed and continued. Should the reduction in corrosion rates not be established then further corrective action will be required.

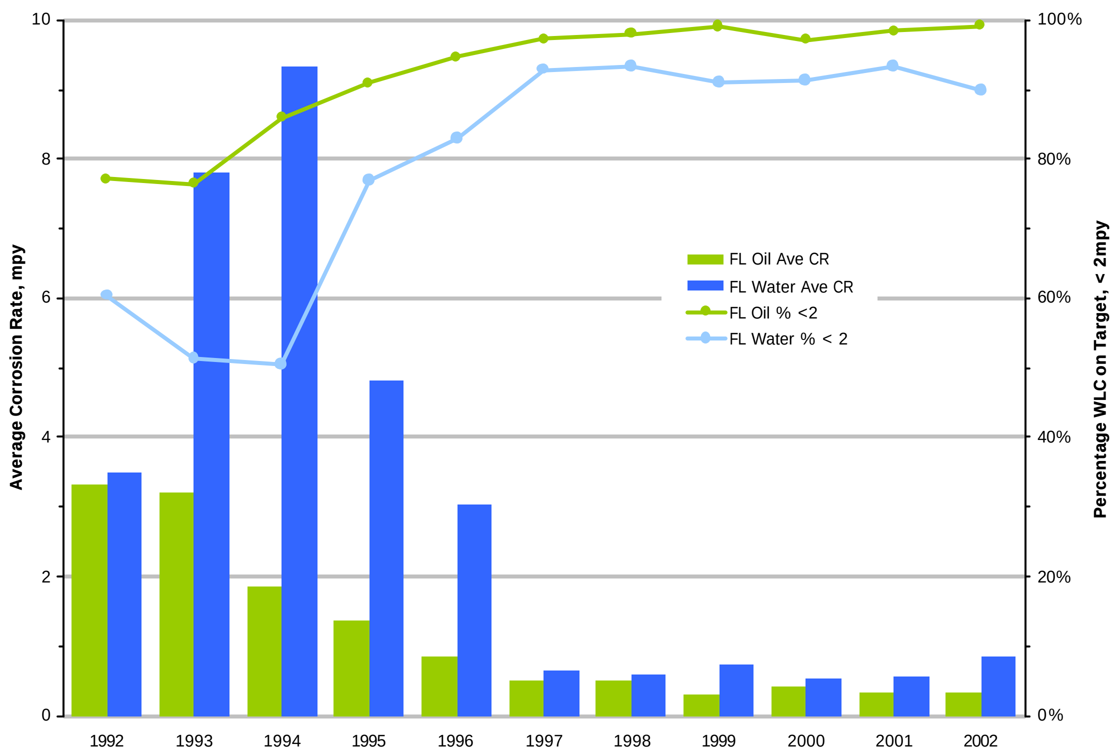

Figure C.12 Flow Line Summary by Equipment and Service for Corrosion Coupon Data

Section C.6 1992 to Date System Summary

The figures in Section C.6 provide system-by-system summary since 1992 for the major corrosive process streams at GPB. Figure C.12 shows the corrosion rate and corrosion conformance performance since 1992. The figure shows that the performance in the 3-phase production system has been maintained or slightly improved from 2001. The performance of the water injection flow lines has deteriorated from 2001 to 2002. This deterioration is as a result of the on-going problems in the SW injection system.

Figure C.13 shows the corrosion rate and corrosion conformance for the well lines. The well line 3-phase system has remained essentially constant between 2001 and 2002. For the produced water well lines there has been a significant improvement between 2001 and 2002, however, this improvement has only returned the system to the levels seen in 1999 and 2001.

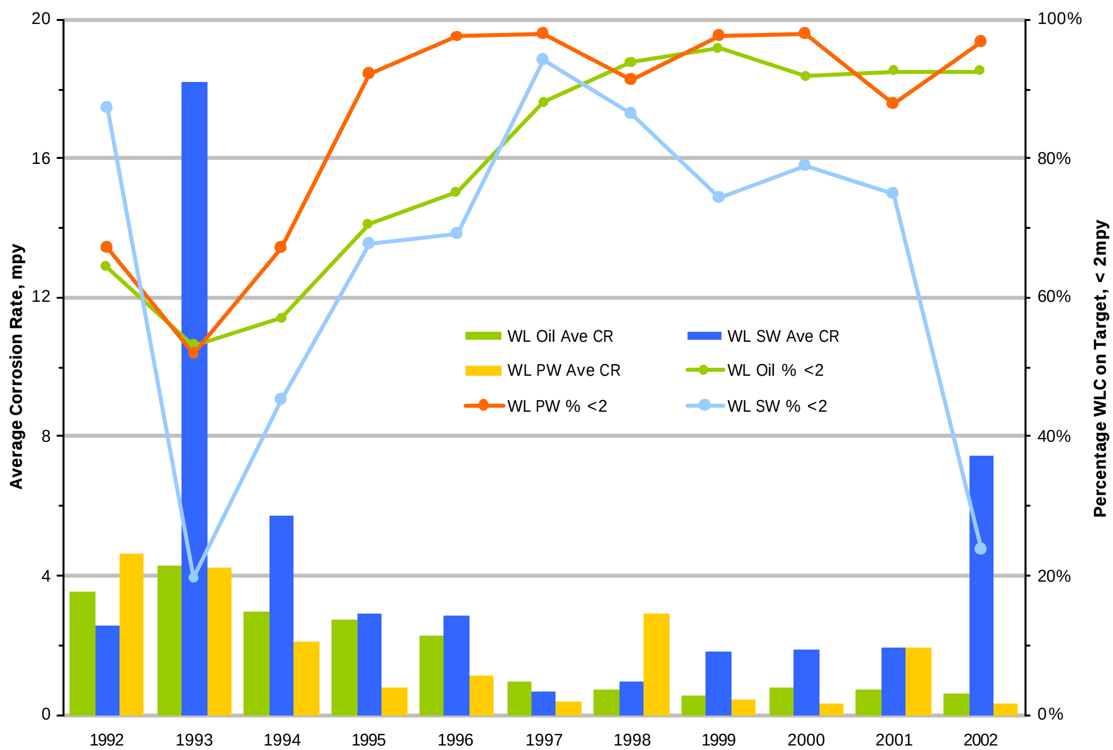

Figure C.13 Well Line Summary by Equipment and Service for Corrosion Coupon Data

As might be expected, the well lines in seawater service show a marked reduction in performance, both in terms of deterioration in the corrosion rate and in the level of conformance to the 2 mpy target. As is discussed elsewhere there have been a number of changes made to the mitigation programs in the SW system with the intention of addressing this deterioration in performance in 2003.

In order to assess the relative performance of the corrosion management program today versus that of the last 10 years, Figure C.14 was generated as a summary. The data shows the difference between the 2002 corrosion rate for each of the systems and the best, or lowest, corrosion rate seen in the prior 10 years and the worst, or highest, corrosion rate seen in the prior 10 years. This is an approximate measure of the successes and/or shortcomings of the program today versus the 10-year history and highlights areas for attention.

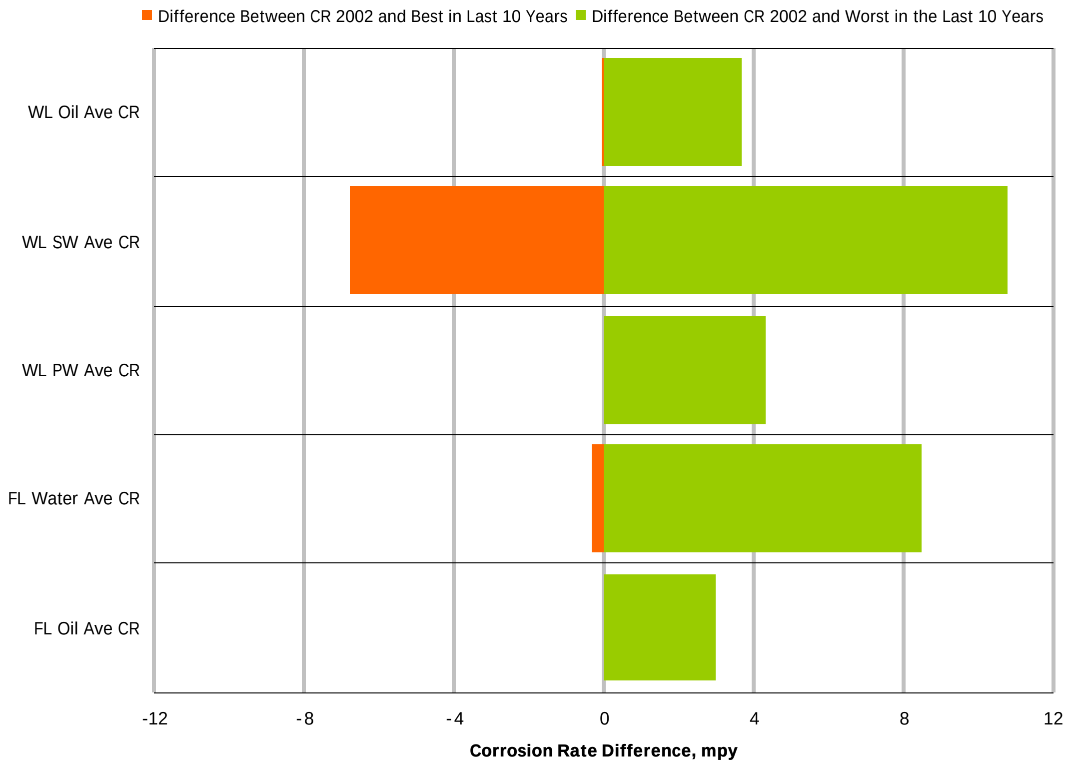

Figure C.14 Corrosion Rate Difference by Service and Type

Figure C.14 shows that the current level of corrosion control as assessed by the difference in average corrosion rate for the system is at or near the best levels of control that have been seen in the last 10 years with the exception of the seawater system. The data given in Figure C.14 is also summarized in the Table C.15.

In summary,

> **Flow Line Oil Service** - Consistent with historical best performance, 99% of coupons pulled in 2002 met or beat the corrosion control target of 2 mpy. Significant improvements in performance occurred from 1992 to 1997 when the average CR was reduced from 3.3 to 0.5 mpy, ~85% improvement, and conformance to the 2 mpy target was increased from 77 to 97%,

~25% improvement. Since then, CR and target conformance performance has increased subtly to the 2002 values of 0.3 mpy and 99%, respectively.

Well Line Oil Service - Slightly under historical best performance, 93% of coupons pulled in 2002 achieved the corrosion control target of 2 mpy or less. Significant improvements in performance occurred from 1992 to 1997 when the average CR was reduced from 3.6 to 1.0 mpy (~70% improvement) and conformance to the 2 mpy target was increased from 64% to 88% (~40% improvement). Since then, CR and target conformance performance has increased to the 2002 values of 0.6 mpy and 93% respectively. Continued improvements are expected due to corrosion inhibitor distribution optimization (individual target rates and expansion of continuous injection systems).

System	2002 CR mpy	Best mpy	(2002 – Best) mpy	Worst mpy	(2002 – Worst) mpy
FL Oil Ave CR	0.33	0.31	-0.02	3.32	2.99
FL Water Ave CR	0.86	0.54	-0.32	9.34	8.48
WL PW Ave CR	0.32	0.30	-0.02	4.61	4.3
WL SW Ave CR	7.46	0.68	-6.8	18.0	10.7
WL Oil Ave CR	0.63	0.57	-0.06	4.3	3.7

Table C.15 Corrosion Rate Difference by Service and Type

Flow Line Processed Oil – These are the flow lines supplying processed hydrocarbon to Pump Station 1 and as might be expected for a very low water cut production stream, the corrosion rates are consistently very low with 100% of the coupons being reported as less than 2 mpy from 1995 to 2002.

Flow Line PW/SW Service – Less than historical best performance, 90% of coupons pulled in 2002 achieved the corrosion control target of 2 mpy or less. Performance deteriorated from 1992 to 1994 when average CR increased from 3.5 to 9.3 mpy and conformance to the 2 mpy target reduced from 60 to 51%. However, significant improvements occurred from 1994 to 1997 when the average CR was reduced to 0.7 mpy (~90% improvement) and conformance to the 2 mpy target was increased to 93% (~80% improvement). Since then, CR and target conformance remained relatively constant until 2002 when performance dropped subtly to 0.9 mpy and 90% respectively.

Well Line PW Service – Average CR and percent conformance with the 2 mpy target were consistent with historical best performance at 0.3 mpy and 97%. Two excursions occurred in 1998 and 2001, these most likely resulted from reduced system velocities (countered by implementing PW corrosion inhibitor evaluations) and oil system corrosion inhibitor chemistry changes (countered by modifying chemistry) respectively. Continued increase in performance is expected due to expansion of a corrosion inhibitor program designed specifically for the PW system.

Well Line SW Service - Average CR and % conformance with the 2 mpy target declined substantially in 2002. Only 25% of coupons pulled in 2002 achieved the corrosion control target of 2 mpy or less with an average CR of 7.5 mpy. As a result, a set of specific corrective actions have been implemented in 2001 and 2002, which are expected to reduce the corrosion rates and return the system to corrosion rates that meet target.

As an overall representation of the progress of improving corrosion control at GPB, Figure C.16 shows the aggregate performance for all equipment and all services discussed in this report. The figure shows that average corrosion rates have fallen by 80% from 2.3 mpy in 1995 to 0.5 mpy in 2002 and that the number of coupons meeting or beating the 2 mpy target has increased from 76% in 1995 to 95% in 2002.

It should be noted that the majority of the pipelines are in 3-phase (OIL) service and hence the majority of the corrosion monitoring is also in 3-phase service. As a consequence, the aggregate data shown above is dominated by the performance of the 3-phase system.

Section C.7 Electrical Resistance Probes

Electrical Resistance (ER) probes are installed in various locations to monitor corrosion rates in flow lines throughout the GPB field piping systems. ER probes show increases due to material loss from corrosion and the measurements are converted to provide corrosion rates in mils per year (mpy). Field ER probes are equipped with remote data collectors (RDC), which measure and record the metal loss data at specified time intervals. The RDC units throughout GPB are set to record metal loss data every 3 hours. This provides an adequate number of data points to assess corrosion rates while maximizing battery life in the units.

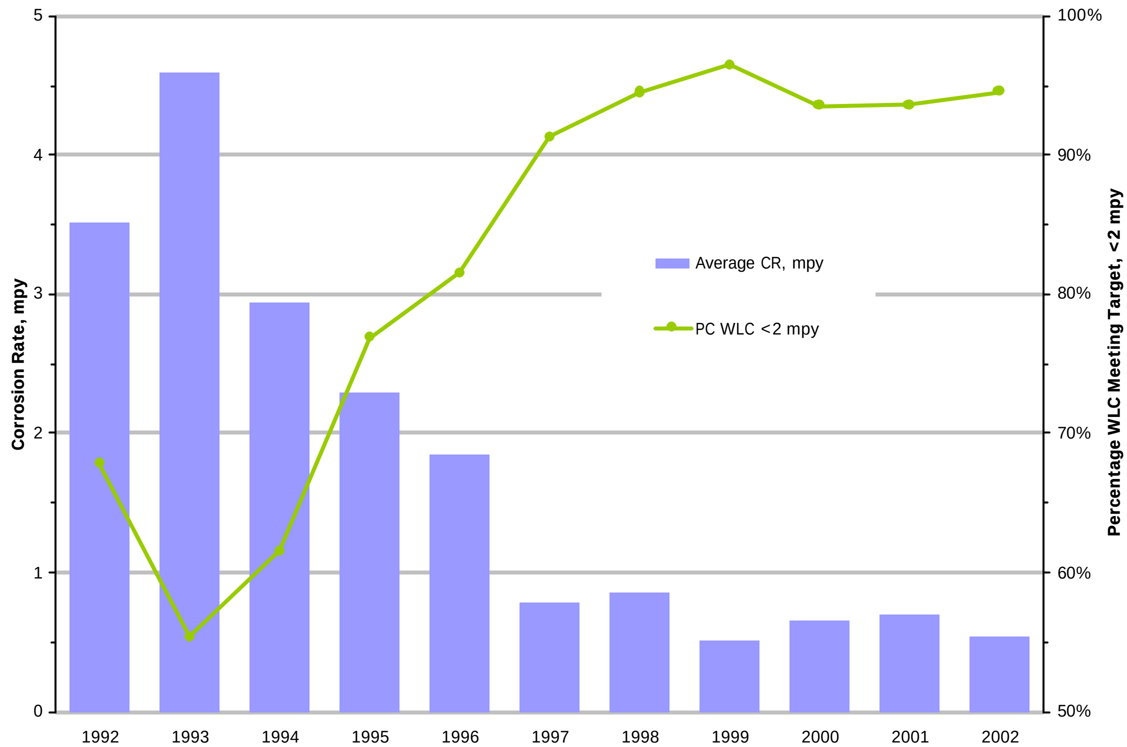

Figure C.16 GPB Aggregate Performance

The type of ER probes used is a T-10 that has 5 mils of metal thickness available for use. All flow line probes are replaced based on 1-year service, or when one half the usable metal thickness has been used. This reduces false negative and false positive readings as a result of a bad, used up, or unresponsive probe.

ER probes are located on both the upstream (well pad) end and downstream (gathering center) end of all flow lines located on the West side of GPB. On the East, probes are located on the downstream (flow station) end of the flow lines only. Expansion to include the upstream location of the flow lines for the East is under review.

ER probe data is collected in the field and uploaded to the corrosion and inspection database once per week. More frequent readings can be made to closely monitor suspect locations/readings. The data is then reviewed and analyzed to identify any negative trends that need to be addressed. After verifying an increase in corrosion rates based on the probe data, a corrosion inhibitor increase may be recommended, as discussed in Section D and shown in the example given in Figure C.17.

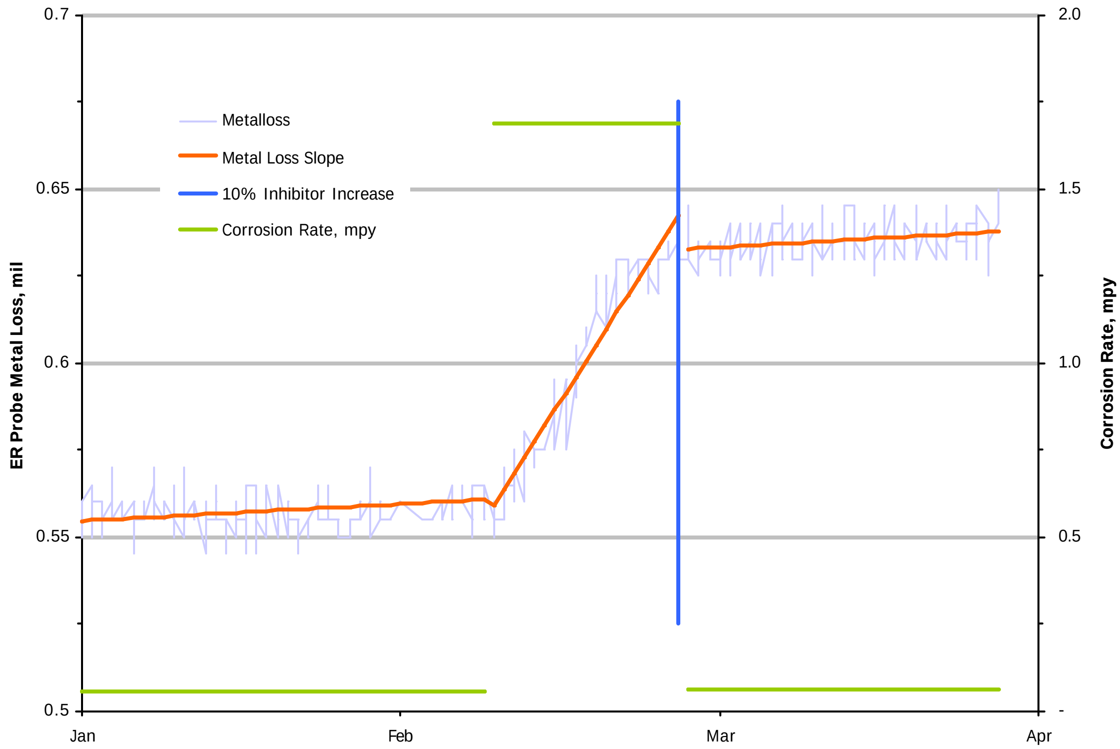

Figure C.17 ER Probe Inhibitor Change Example

The ER probe rate target is less than 2 mpy. In 2002 there were 137 occurrences when the ER probes exceeded 2 mpy as compared to 193 occurrences in 2001. Only 6 occurrences of the 137 were attributable to increases in corrosion rate. The corrosion inhibitor rate was increased for each of the 6 occurrences – see Section H.

The remaining 131 were as a result of,

- Probe element failure
    - Mechanical damage
- Thermal swings as a result of operational fluid rate changes
- Exceeded probe life, 12 months or 50% of active element
- Loss of electrical power/batteries

Additional information on the use of ER probes in the corrosion management process is provided in Section D – Chemical Optimization Activities.

Section C.8 Coupon Processing Recommended Practice.

Coupons are processed and analyzed consistent with NACE recommended practice NACE RP0775-99.

Section D

Chemical Optimization Activities

Section D Chemical Optimization Activities

Section D.1 Chemical Optimization

Chemical optimization is an on-going process that encompasses a broad range of activities, from developing new corrosion inhibitors for improved performance, to the allocation of extra chemical for additional corrosion control. The following sections describe the main areas in this range including chemical development, field wide chemical deployment, chemical usage and finally corrosion control.

Section D.2 Corrosion Inhibitor Development

The development of new corrosion inhibitors starts in the R&D laboratories of the chemical suppliers with potential chemistries being tested for effectiveness under a range of conditions to simulate GPB fluids. Once these preliminary test chemistries have passed the laboratory screening process, the promising products are tested under field conditions using dedicated test facilities at GPB.

Typically, using a standardized protocol, one or two new products are tested each month on a small scale test using an individual well line with each test lasting ~10 days and using approximately 100 gallons of the corrosion inhibitor being evaluated. Products that successfully pass the well line test program are then considered for a large-scale field trial.

The large-scale field trial involves converting between one and three well pads to the test product for 90 days and using 20-40,000 gallons of test chemical. This enables corrosion probe, coupon, and inspection data to be generated to verify the test product's effectiveness as a corrosion inhibitor. The large-scale field trial also allows assessment of the impact of the product on oil separation and stabilization process.

The test process is summarized in Table D.1

As an example, the ER probe results from a typical cross-country flow line test are shown in Table D.2 and are summarized in Figure D.3. As can be seen from the figure and the details in the table, the test chemical in this example was not cost effective and therefore was not utilized across the field.

A second example, utilizes the output from the weight loss coupon program. This example from a test performed in 2001, demonstrates the need/value of multiple monitoring techniques when evaluating corrosion inhibitor performance. The trial product was tested for a 90-day period with no negative response observed by the ER probes. However, after the 90-day test period the corrosion coupons were pulled and showed relatively high general corrosion and pitting rates - see Figure D.4. The product was evaluated as a failure and the incumbent product was re-instated based on the coupon results. Corrosion inhibitor tests use all monitoring tools such as corrosion probes, coupons, and inspection data to determine corrosion control performance.

Location	Test	Description
Laboratory	Wheel-box Test	Performance of new potential corrosion inhibitor actives is compared to high performing actives. The test conditions simulate GPB and the test is run for 24 hours. Performance is determined by coupon weight loss.
	Kettle Test	This investigates the ability of an inhibitor formulation to partition from an oil phase into a brine phase under stagnant conditions. Test duration is 16 hours and corrosion rate is determined by linear polarization resistance (LPR) probes.
	HP Autoclave	This method determines the performance of inhibitors under high pressure and high temperature conditions. Monitoring method is by either coupon weight loss measurements or LPR. Test duration varies from 1 to 7 days.
	Jet Impingement	A once-through jet impingement configuration evaluates the performance of an inhibitor formulation under extremely high shear conditions. The persistency of the inhibitor film can also be determined. Test duration is one hour and corrosion rate is determined by LPR measurements.
	Flow Loop Test	The ultimate laboratory scale test that simulates temperature, pressure and flow conditions including velocity and water cut. Typical test duration is 24 hours and corrosion rate is determined by LPR measurements.

Table D.1 Summary Description of the Typical Test Program Components

Location	Test	Description
Field	Well Line Test	Dedicated test lines are used at GPB as the first step in the field-testing process. Typically 100 gals of chemical used with a test duration of 10 days.
	Large Scale Test	1 to 3 well pads using 20-40,000 gallons of corrosion inhibitor with a test duration of 90+ days. Allows the evaluation of corrosion inhibitor performance by ER, WLC, and inspection, as well as impact of product on separation plant performance.
	Evaluation	Products are evaluated against both technical performance and cost effectiveness criterion in order to assess if there is an overall improvement in cost effectiveness.
GPB	Implementation	Once a decision has been made to convert the field to a new product, additional precautions are taken with additional corrosion monitoring and plant performance evaluations in order to assure product efficacy.

Table D.1 (Cont.) Summary Description of the Typical Test Program Components

Status	Chemical	Conc. ppm	CR, mpy	Notes/Comments
Baseline	Incumbent	130	0.2	
Stage 1	Test	150	8.1	Even at a higher dose rate the test chemical was unable to inhibit corrosion to the same level as the incumbent.
Stage 2	Test	170	2.0	Reduces corrosion rate.
Stage 3	Test	190	0.8	Dose rate was increased in order to achieve the same level of corrosion control as the incumbent. At this increased level of corrosion inhibition the test product was uneconomic and the test was terminated.
Return	Incumbent	130	0.1	Re-inject the incumbent product and corrosion rates return to the same level as those prior to the test.

Table D.2 Flowline Test Program Result Summary

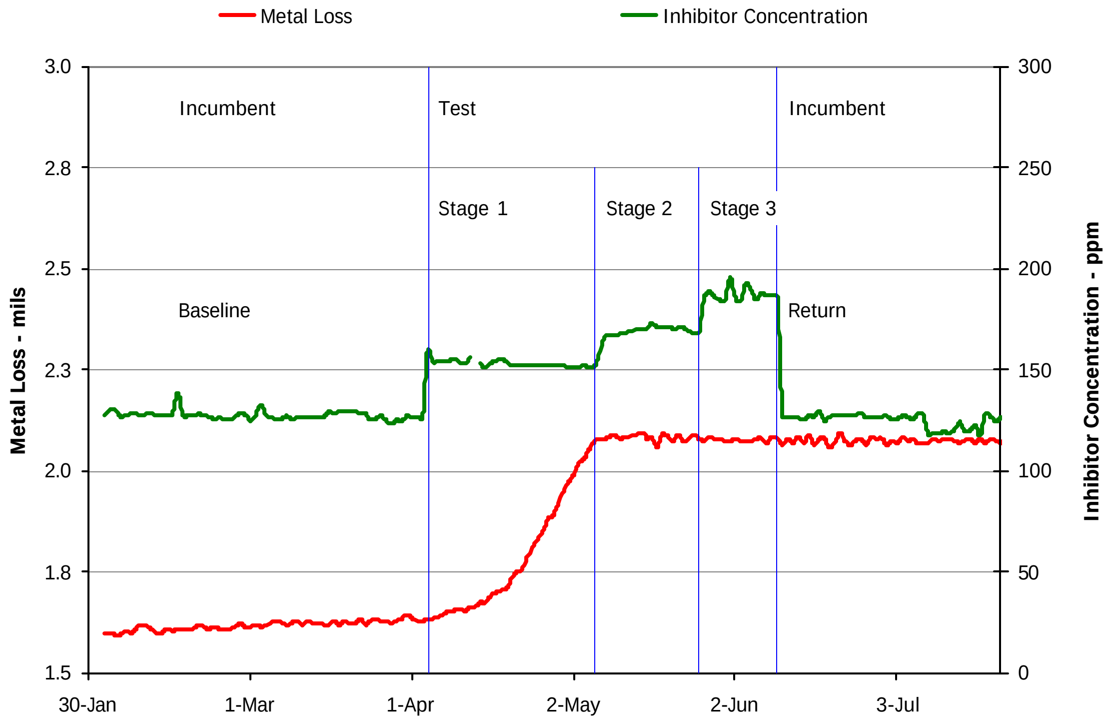

Figure D.3 ER Probe Chemical Optimization Test

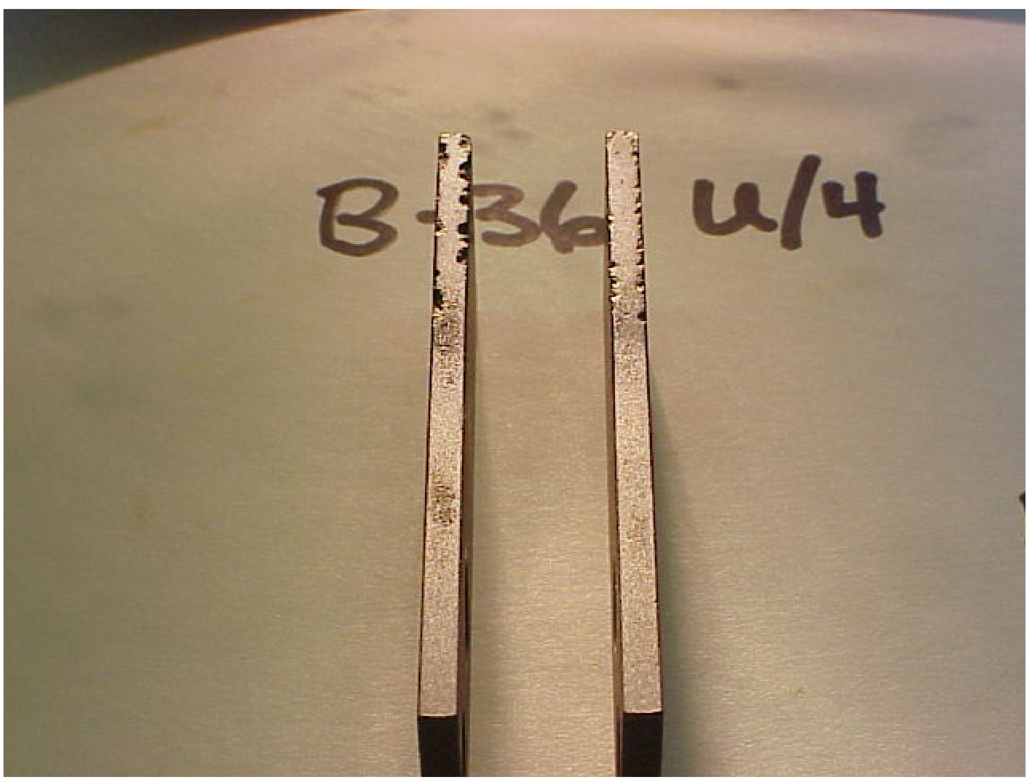

Figure D.4 Corrosion coupons pulled after an 'unsuccessful' chemical trial

Section D.3 Corrosion Inhibitor Testing

Table D.5 below summarizes the number of well line and full-scale flowline tests which have been completed since 1996. As can be seen from Table D.5 and the accompanying chart, Figure D.6, the level of activity has remained relatively constant since 1997 at between 10-14 well line and full-scale flow line trials per year.

	1996	1997	1998	1999	2000	2001	2002
Well line test	2	12	11	10	14	5	12
Flow line test	1	1	1	2	0	1	0
Total	**3**	**13**	**12**	**12**	**14**	**6**	**12**

Table D.5 Number of Well Line and Flowline Trials

The data prior to 2000 is incomplete and represents the test work completed on the heritage WOA only. This level of activity represents a substantial investment of resources towards the development of more effective corrosion inhibitors.

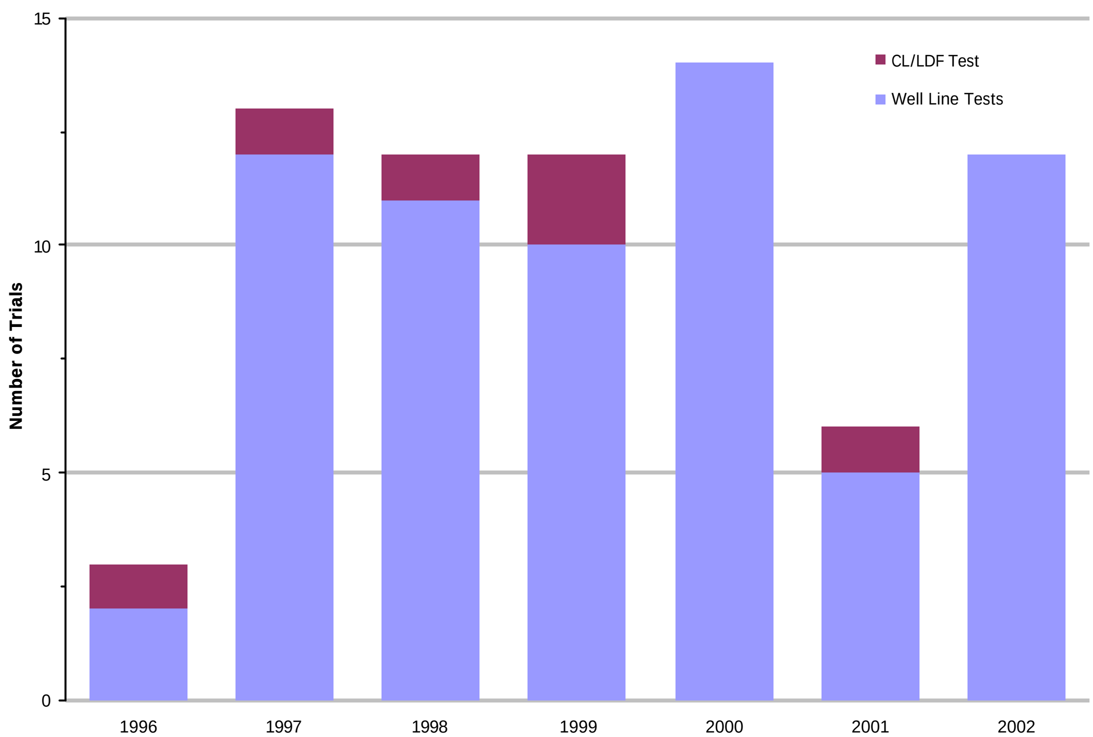

Figure D.6 Number of Well Line and Flowline Trials

Section D.4 Field Wide Corrosion Inhibitor Deployment

The chemical development and testing program has been highly successful in recent years, with 18 new products being developed for use in the continuous wellhead inhibition program since 1995. All these changes over the last 8 years represent a significant improvement in cost effectiveness and corrosion control performance.

Table D.7 summarizes the changes in corrosion inhibitor products since 1995. The table does not include test products which did not make it to field wide usage. In addition, the summary table does not include summer versions of products that differ only in pour point from the winter version shown in the table.

Section D.5 Corrosion Inhibitor Usage and Concentration

Another measure of chemical optimization is the amount of corrosion inhibitor used relative to the volume of water produced from the reservoir. Table D.8 summarizes the annual water production, corrosion inhibitor volumes, and concentrations since 1995. The inhibitor volumes are expressed as a 'winter product equivalent', i.e. the lower volumes of highly concentrated chemical used during the summer have been normalized to the winter equivalent.

Supplier	Chemical	1995	1996	1997	1998	1999	2000	2001	2002
Nalco Exxon	EC1110A	■	■						
Nalco Exxon	EC1259			■	■				
Nalco Exxon	97VD129				■	■	■		
Nalco Exxon	98VD118				■	■	■		
ONDEO Nalco	99VD049					■	■	■	
ONDEO Nalco	01VD017							■	
ONDEO Nalco	01VD121							■	■
Champion	RU205	■							
Champion	RU210	■	■	■					
Champion	RU223	■	■	■	■				
Champion	RU258			■					
Champion	RU271				■	■	■		
Champion	RU126A						■		
Champion	RU256[1]			■	■	■	■	■	■

[1] Used for the batch treatment of well lines while the remaining chemicals are all used for continuous application

Table D.7 Summary of the Chemical Deployment History at GPB

The concentration of inhibitor in the water phase provides a relative measure of the effectiveness of the chemical used to control corrosion. However, such data can be misleading as the types of corrosion inhibitors used vary from year to year, as shown in Table D.7. As more cost effective chemicals are developed, volumes and concentrations will change depending on the individual product's performance characteristics. There has also been a shift from batch treatments to continuous injection of chemical at the wellhead. The latter is more efficient in terms of protection achieved per gallon of chemical and therefore lower chemical usage would be expected.

The changes directed at developing more cost effective corrosion inhibitors are counteracted by the increasing water cuts associated with an ageing oil field and increased flow velocities due to increased gas handling capacity. These changes generally increase the amount of chemical required to control corrosion. As Figure D.9 shows, the volume of corrosion inhibitor has increased since 1995 while the water volumes have remained relatively constant.

Year	**H_2O Production** 10^6 bbl/yr	**Water Cut**	**CI Usage** 10^6 gal/yr	**CI Concentration** ppm
1995	455	59 %	1.62	85
1996	460	62 %	2.05	106
1997	457	62 %	2.21	115
1998	426	66 %	2.53	141
1999	416	68 %	2.28	130
2000	438	70 %	2.73	148
2001	398	70 %	2.63	157
2002	407	71 %	2.45	143

Table D.8 Summary of the Chemical Usage History at GPB

However, the ultimate measure of whether or not enough corrosion inhibitor is used can only be determined by consideration of other factors such as corrosion monitoring data and/or the amount of active corrosion detected by the inspection program.

The metrics in Figure D.9 deal with chemical usage at the field level but much of the chemical optimization activity focuses on injecting the correct amount of corrosion inhibitor to each piece of equipment. The inhibitor requirement is driven by factors such as water cut, water volume, flow regime, and condition of the equipment and varies over a wide range, from a few parts per million (ppm) to several hundred ppm.

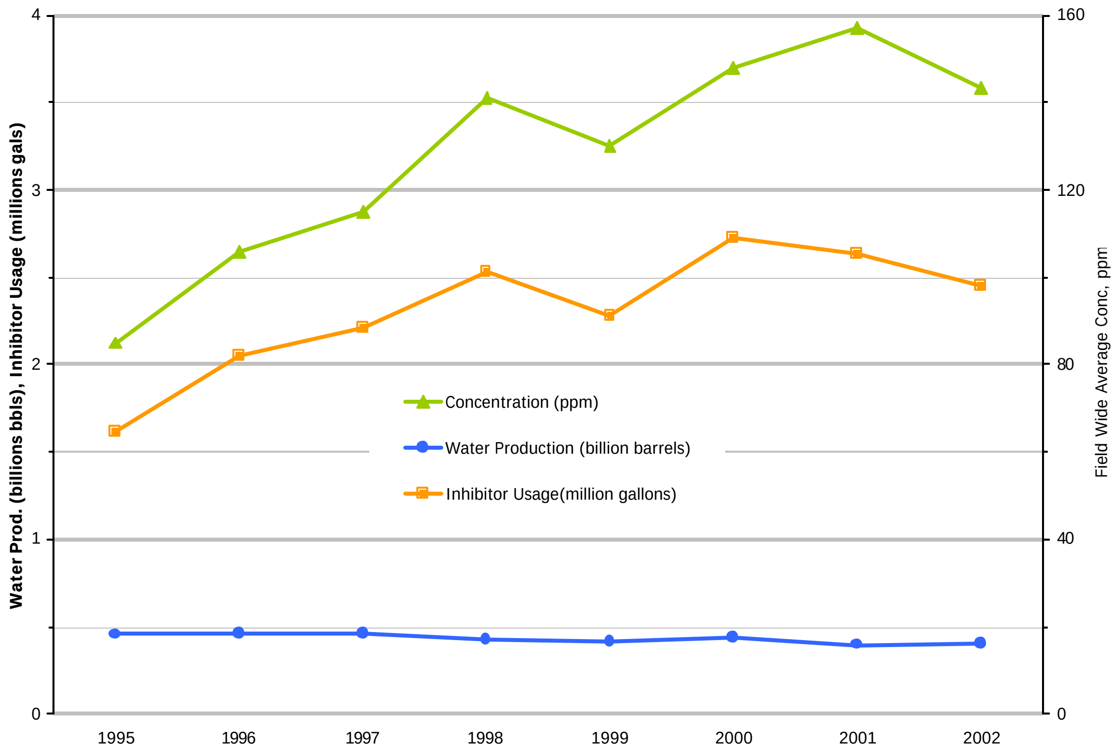

Figure D.9 Field Wide Chemical Usage

For 2002 the target chemical usage was 2.46 million gallons as compared to actual usage of 2.45 million gallons; this represents near perfect performance by the chemical crews for corrosion inhibitor injection in 2002.

Section D.6 Corrosion Inhibition and Corrosion Rate Correlation

As discussed in the section on corrosion monitoring, the reduction in corrosion rates in the 3-phase production system flow lines and well lines is largely attributable to the implementation of an aggressive corrosion inhibition program across GPB.

Figure D.10 shows the correlation between the increased level of corrosion inhibitor and the reduction in average corrosion rate from 1995. As might be expected, the decline in average corrosion rate correlates with the increase in corrosion inhibition levels over time. The inhibition levels have increased approximately 70% from 1995 to 2002, with a field-wide average concentration of 85 ppm to 143 ppm. As a result the corrosion rates have fallen from 1.4 mpy in 1995 to 0.3 mpy in 2002.

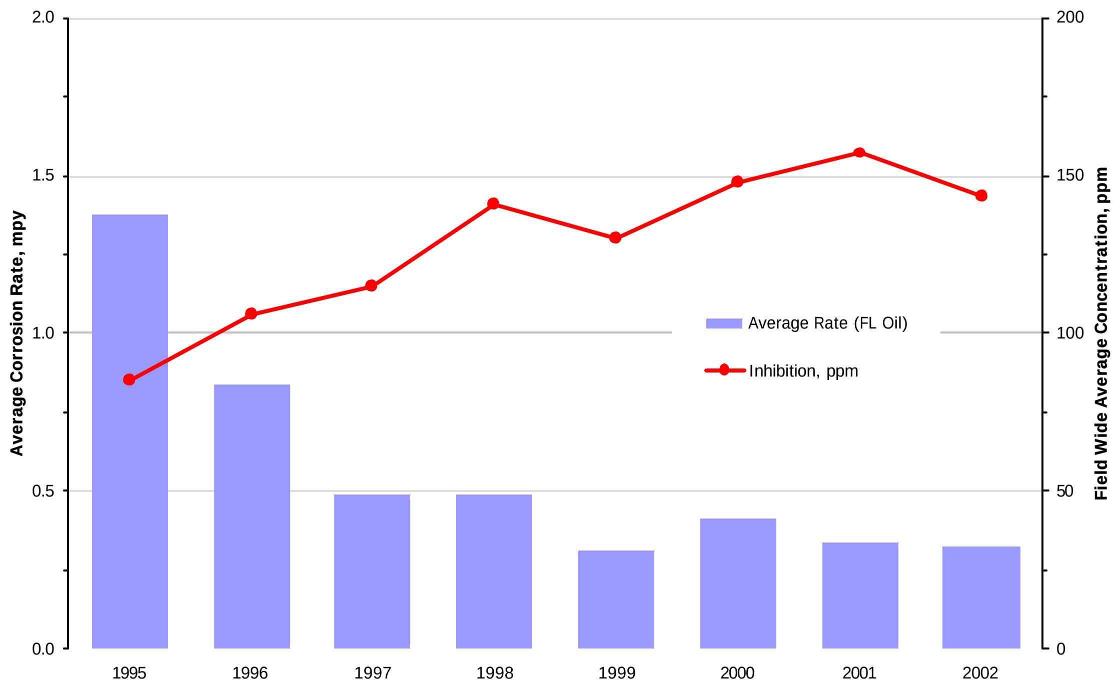

Figure D.10 Average Corrosion Rate Versus Inhibitor Concentration

Figure D.11 shows the annual field-wide average corrosion inhibitor concentrations and annual average corrosion rates for 3-phase production flow lines plotted against each other. The figure shows how the additional corrosion inhibitor has reduced the corrosion rate through time, but also shows an inherent limitation of corrosion inhibition as the minimum corrosion rate (or maximum corrosion inhibitor efficiency) is approaching an asymptote of ~0.25 mpy.

Section D.7 ER Probe and Corrosion Inhibitor Response

This section of the report describes, by example, the methodology by which corrosion inhibitor concentration is increased as a result of corrosion monitoring through the use of ER probes. ER probes are in use across GPB on the major 3 phase production flow lines.

ER probe data is automatically stored 8 times per day (or every 3 hours) using battery powered data loggers. The data is downloaded weekly and then transferred to the corrosion and inspection database once per week for analysis.

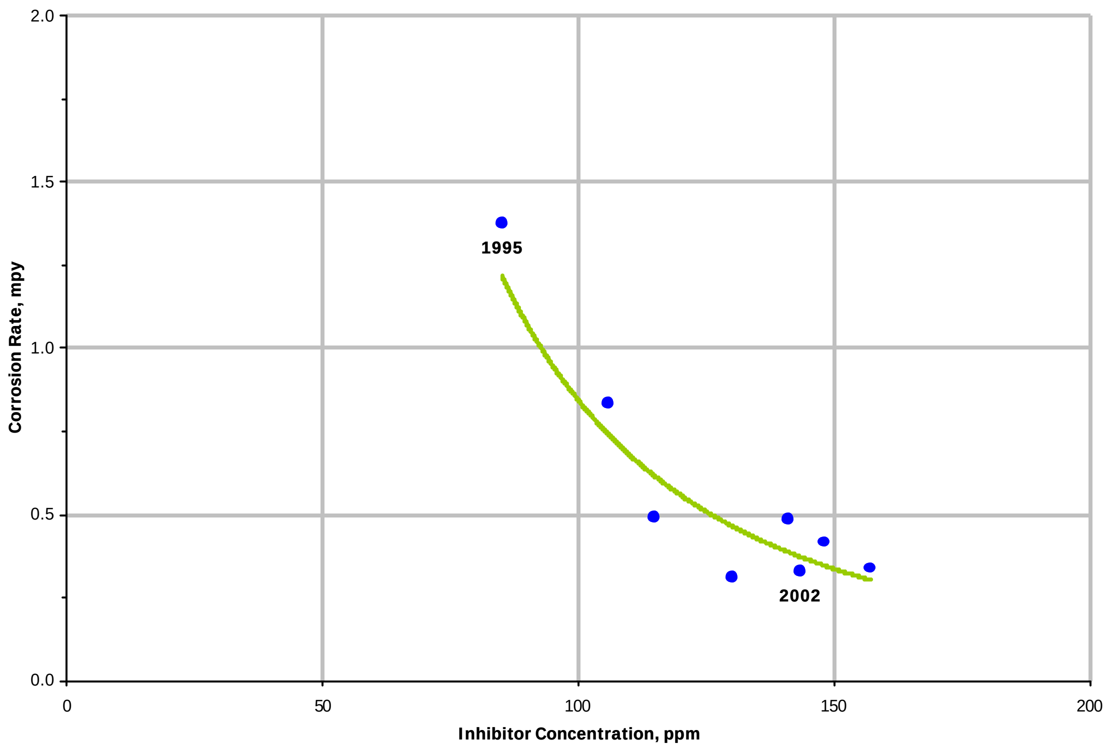

Figure D.11 Corrosion Inhibitor Concentration vs. Corrosion Rate

Figure D.12 (a) and (b) gives an example of the use of ER probes in managing changing corrosion conditions in A-74, one of the large diameter flow lines at GPB. Figure D.12 (a) shows the ER probe readings and derived corrosion rates, over a period of approximately 6 months. For the first 2 months the measured corrosion rate is less than 2 mpy. However, in mid-July there is a significant increase in corrosion rate that triggers action. Initially, the response is to conduct a detailed review of the critical operational parameters such as the corrosion inhibitor injection rates, production history, fluid velocity, inspection results and other monitoring information.

Following the initial data review, further ER probe data shows that the increasing corrosion trend is continuing and as a consequence the corrosion inhibitor concentration is increased 10% from 128 ppm to 141 ppm.

With the increase in corrosion inhibitor concentration, the corrosion rate is significantly reduced. This corrosion rate reduction is clearly demonstrated by the long-term corrosion rates derived over several months of ER probes data. This long-term data is shown in Figure D.12 (b) and summarized in Table D.13.

The data in Table D.13 clearly shows the long-term effectiveness of the corrosion inhibitor increase with the corrosion rate in the flow line remaining below 1 mpy for the 4-month period following the 10% inhibitor concentration increase.

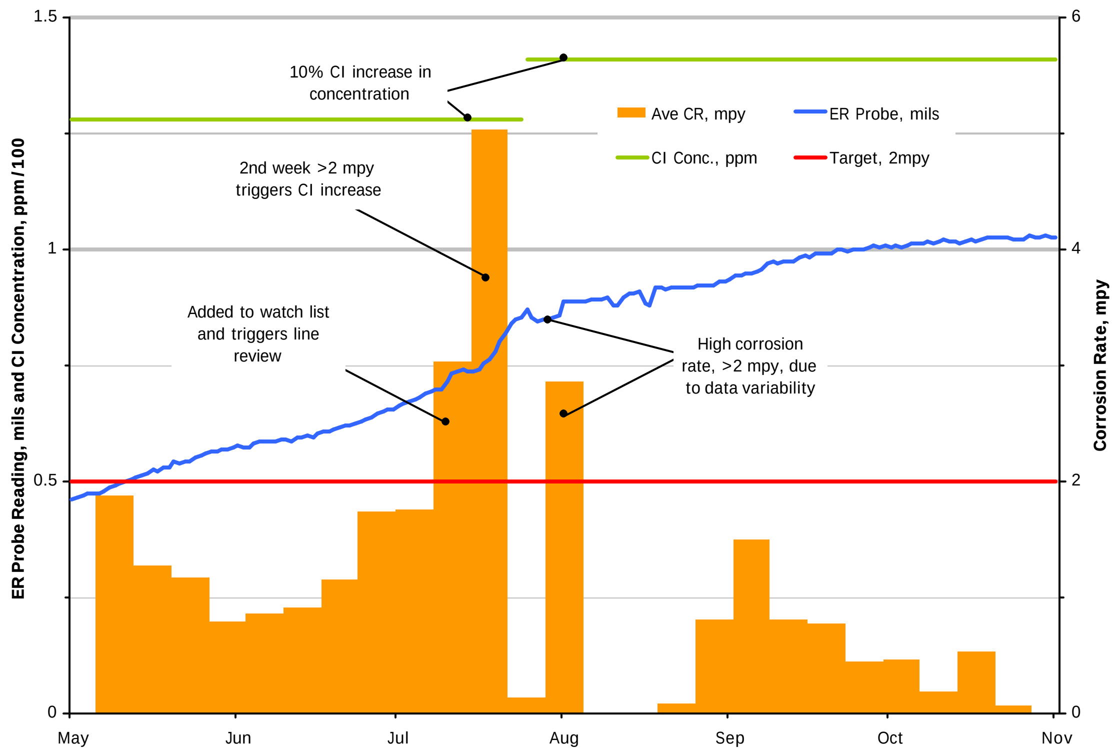

Figure D.12 (a) Corrosion Inhibitor Concentration vs. Corrosion Rate

Time Period	CR, mpy	Comments
6-May to 7-July	1.1	Corrosion rates consistently below target rate of 2 mpy
8-July to 28-July	3.3	Corrosivity of the flow line increasing over successive weeks. Corrosion inhibitor concentration increased 10%.
29-July to 22-Sept	0.9	Corrosion rates fall below target level following increase in corrosion inhibitor concentration.
22-Sept to 27-Sept	0.3	Continued corrosion control below target corrosion control level of 2 mpy

Table D.13 Corrosion Inhibitor Concentration vs. Corrosion Rate

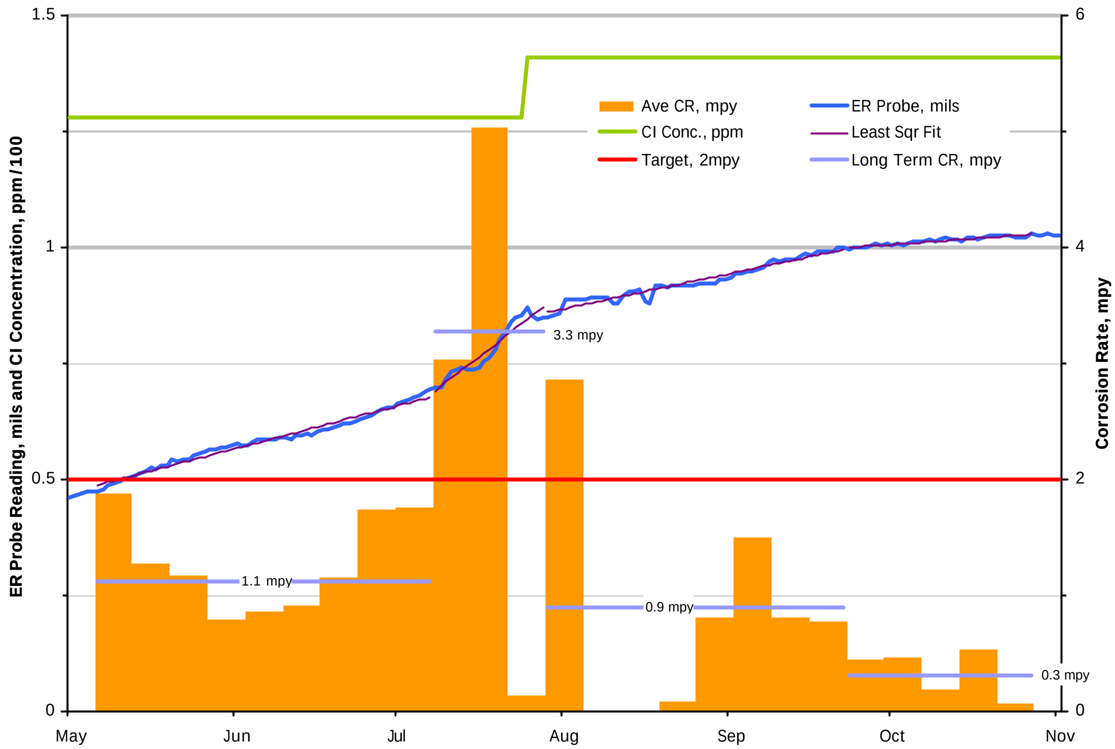

Figure D.12 (b) Corrosion Inhibitor Concentration vs. Corrosion Rate

Section D.8 Chemical Optimization Developments

Historically tank levels or tank strapping has been recorded manually in the Chemical Operators' logbooks. This manual process has made access to chemical usage data for individual lines difficult. With the advent of handheld data recorders and bar-code readers, the corrosion inhibitor management program at GPB is moving toward an electronic system for managing chemical usage and tank strap reading data.

Starting 2Q 2002, the major corrosion inhibitor tanks have been individually identified and bar-coded and the Chemical Operators assigned handheld data recorders with a built-in barcode reader. This enables the operators to uniquely identify tanks and enter the tank strap reading directly into the handheld device and hence download into the database without the need to transcribe the information.

The automated uploading of chemical usage information into the database eliminates a number of manual steps during which the data was consolidated and transcribed resulting in numerous transcription errors. The improved quality and quantity of data will allow for more efficient and effective corrosion inhibitor usage and management in the future.

In particular, pad level injection rates should more closely match the targeted value providing better corrosion management. Also with better visibility into the tank level data, there will be a more capable inventory management providing for just-in-time delivery to individual tanks, reducing the number of deliveries, and hence the numbers of fluid transfer operations. The reduced number of fluid transfer operations reduces the potential for spills and leaks associated with tank filling operations.

An example of the data that is now available is given in Figure D.14. The figure shows the tank strap reading history for C-Pad fluids that flow into GC-3 via a 24" diameter flow line. This and similar data sets will allow for much improved and consistent levels of corrosion inhibitor injection for the future.

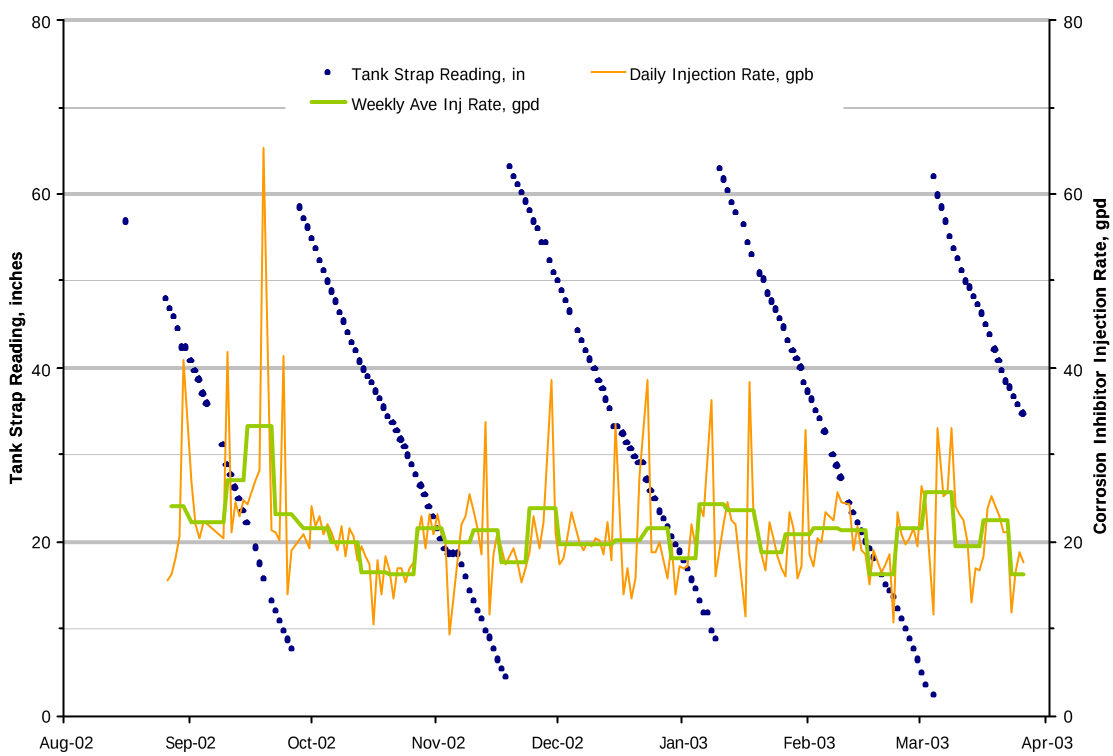

Figure D.14 Tank Strap Reading and Inhibitor Usage

Section D.9 Chemical Optimization Summary

In summary, chemical optimization covers a number of different areas from chemical testing and development to field-wide deployment of new products delivering improved levels of corrosion control more cost effectively. However, all this activity is ultimately directed toward one end — the reduction in corrosion rate. The effectiveness of the chemical optimization program in delivering improved corrosion rates is clearly demonstrated.

Section E

External / Internal Inspection

Section E External/Internal Inspection

The inspection program covers the piping, piping components, pressure vessels and tanks across GPB. Radiographic imaging or ultrasonic flaw evaluation makes up the majority of inspection techniques however; there are some specialized techniques in use for particular applications. The details for these techniques are shown in Table B.12 (c).

A number of factors contribute to the selection and allocation of inspection resources including, but not limited to, current equipment condition, current known rate (from inspection or corrosion monitoring) of wastage, operational risks associated with the fluids being transported, active or passive corrosion mitigation, and design and age of the equipment. Details of the individual inspection programs are provided in Table B.11 (c). The inspection program is one element in the overall integrity management of equipment in GPB.

Section E.1 External Inspection

This section summarizes the inspections performed to detect external corrosion and the results of those inspections. External corrosion is primarily associated with water ingress into the thermal insulation of pipelines at GPB, in particular, at the field-applied insulation joints.

The pipelines are generally uncoated carbon steel and are therefore vulnerable to external corrosion if water comes into contact with the outer surface of the pipe. The pipelines are constructed from either single or double joints (40-80 ft. long) with a shop-applied polyurethane insulation protected with a galvanized wrapping. The area around the girth welds are insulated with 'weld packs.' The detailed design of weld packs varies but all are prone to water ingress to a greater or lesser extent.

The main challenge in managing Corrosion Under Insulation (CUI) is the detection of the external corrosion damage. Water ingress into the weld packs is a random process and therefore it is difficult to apply highly specific rules to target the inspection program.

In order to detect CUI, a recurring screening program has been implemented as the best method to identify equipment and locations at risk. Prioritization of inspection surveys is determined by configuration, average temperature of the equipment, age of equipment, and/or the last time a complete screening process was completed. If screening has been completed, sites are revisited at prescribed intervals. As a result of findings from the screening process, the extent or recurring frequency of any additional examinations is determined.

The CUI program covers all cross-country flow lines and well lines. There are approximately 300,000 weld packs at GPB, of which approximately 200,000 are off-pad and 100,000 are on-pad.

Section E.1.1 External Inspection Program Results

Table E.1 and Figure E.2 show the number and results of the external corrosion inspections performed between 1995 and 2002. The data includes all the Tangential Radiographic (TRT) techniques applied to external corrosion, including Automated-TRT (ATRT), and C-Arm Fluoroscopy (CTRT).

	1995	1996	1997	1998	1999	2000	2001	2002
Well Line								
Activity Level	-	36	1680	946	2376	5233	13122	23797
Corrosion Detected	-	6	234	66	72	242	711	345
%Corroded	-	17%	14%	7%	3%	5%	5%	1%
Flow Line								
Activity Level	1508	11472	17934	10315	8119	5179	3963	18931
Corrosion Detected	245	763	1491	763	546	253	103	692
%Corroded	16%	7%	8%	7%	7%	5%	3%	4%
GPB Overall								
Activity Level	1508	11508	19614	11261	10495	10412	17085	42728
Corrosion Detected	245	769	1725	829	618	495	814	1037
%Corroded	16%	7%	9%	7%	6%	5%	5%	2%

Table E.1 External Corrosion Activity and Detection Summary

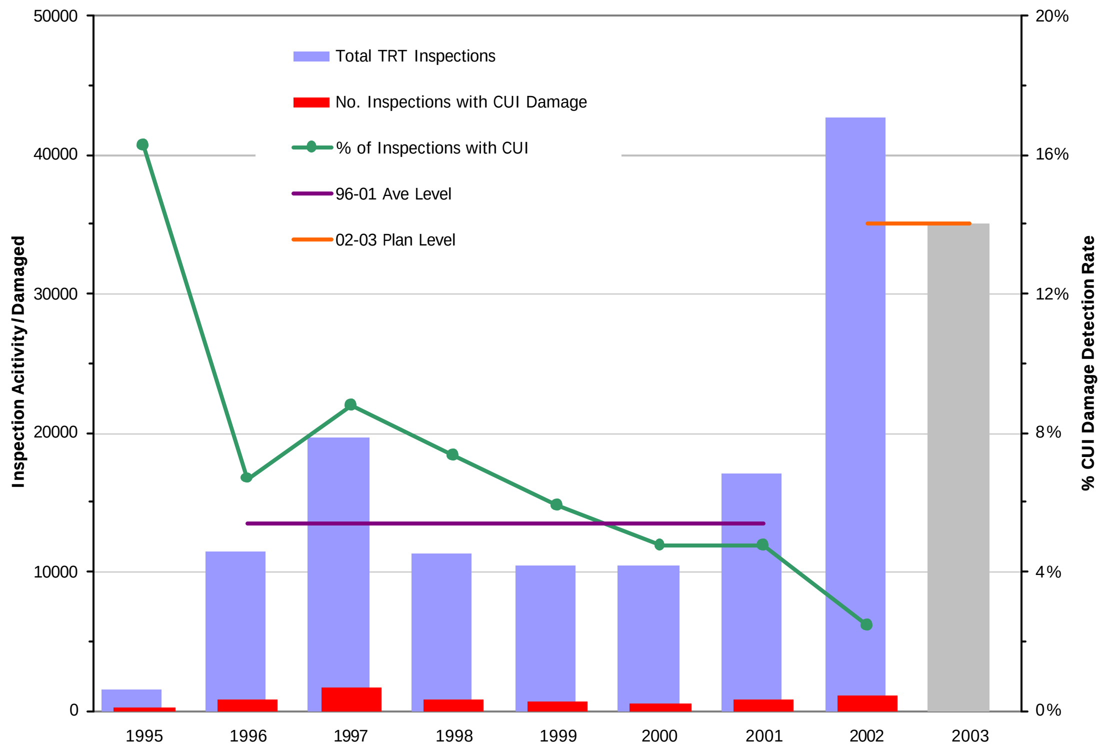

Figure E.2 External Corrosion Activity and Detection Summary

Table E.1 and Figure E.2 summarize the annual level of CUI inspection activity, the number of damaged locations found through the inspection program, and the percentage of inspected locations that exhibited damage. In general, the inspection levels over the period 1996 to 2001 remained relatively constant at an average of ~13,000 per year. The inspection level in 2002 was greater than three times the historical average and ~43,000 inspections were completed. In contrast, the percentage of locations found with damage has fallen from an initial high of >15% to a field-wide average of ~2%.

Table E.3 summarizes the CUI inspection program for the period 1995 to 2002 broken out by service and equipment type, well line and flow line, and the aggregate of both data sets.

The data suggests that there is some dependence of external corrosion occurrence based on service type with the Processed Oil (Export) showing a lower rate of occurrence of 3% compared to water injection service (Water) with an occurrence rate of 9%. This difference is driven in part by the difference in temperature between these services. However, as much variability in damage occurrence is found based on the location and orientation of the weld-pack location.

Service	Flow Line # Insp.	Flow Line # Corr	Flow Line % Corr	Well Line # Insp.	Well Line # Corr	Well Line % Corr
3 Phase	24350	1728	7%	30964	1266	4%
Export	312	10	3%	-	-	-
Gas	40335	1743	-	11007	177	0%
Other	41	2	5%	187	22	0%
Water	12383	1373	11%	5032	211	4%
Total	77421	4856	6%	47190	1676	4%

Service	Aggregate # Insp.	Aggregate # Corr	Aggregate % Corr
3 Phase	55314	2994	5%
Export	312	10	3%
Gas	51342	1920	0%
Other	228	24	11%
Water	17415	1584	9%
Total	**124611**	**6532**	**5%**

Table E.3 CUI Inspections by Service Type

Table E.4 shows the distribution of insulation joint types based on a sample of approximately ~50,000 locations. For each of the specified joint types, there is an associated CUI incident rate. The overall average CUI incident rate for the sample was 2½% that is consistent with average find rate for the 2002 data set shown in Table E.1.

From Tables E.3 and E.4 it can be seen that there is as much variability in the CUI incident rate between the insulation joint configurations as there is associated with the service type. This suggests that the joint configuration and insulation joint location, along with age, have as much influence on the occurrence of external corrosion at weld-packs compared to the service type and hence temperature.

GPB Joint Design	Joint Type Freq	CUI Incident Rate
Anchor Joint	4.4%	2.8%
Damaged Insul	8.4%	2.0%
Damaged Weld Pack Insul	0.1%	2.4%
Ell Anchor Joint	0.1%	6.8%
Ell Bottom Elev	3.6%	6.3%
Ell Bottom Elev Saddle	0.5%	9.9%
Ell Horiz Saddle	1.0%	8.4%
Ell Horizontal	10.1%	3.8%
Ell Top Elev	2.6%	1.3%
Ell Top Elev Saddle	0.3%	4.5%
Mid-Span Weld Pack	56.4%	1.8%
Saddle Joint	11.1%	3.6%
Vertical Joint	0.1%	5.3%
Wall Penetration	1.2%	1.4%
Average CUI Incident Rate		**2.5%**

Table E.4 CUI Incident Rate by Joint Type

Section E.1.2 Cased Piping Survey Results

Table E.5 shows cased pipe segments inspected in 2002. Potential metal loss areas are reported as anomalies and severity is semi-quantified as minor, moderate, or significant.

The 2002 scope included examination of segments that had not previously been inspected as well as the on going monitoring of reported anomalies from prior years' testing. The near-term strategy for management of cased pipe segments is to complete an initial inspection baseline of all GPB cased piping by year-end 2003. In accordance with the agreement with ADEC, 2002 was year 4 of a 5-year program to complete a baseline inspection on all cased piping segments. To date, baseline inspections have been completed on approximately 80% of the piping segments, which is on track to complete the program by year-end 2003.

Additionally, all cased piping road crossings are visually inspected annually during the summer months. Mitigation includes removal of any material, i.e. debris, gravel, dirt, from the casing ends.

Service	Technique	Segment	Minor	Moderate	Significant	Anomaly Action
3 Phase	E-Pulse	90	27	-	6	Proof/Monitor G-Wave
	G-Wave	27	13	7	-	Monitor Guided Wave
PW/SW	E-Pulse	20	1	-	1	Proof/Monitor G-Wave
	G-Wave	11	-	9	-	Monitor G-Wave
Gas	E-Pulse	95	15	-	22	Proof/Monitor G-Wave
	G-Wave	19	11	5	-	Monitor Guided Wave
PO	E-Pulse	6	2	-	1	Proof/Monitor G-Wave
	G-Wave	1	1	-	-	Monitor G-Wave
Total		**269**	**60**	**21**	**30**	

Table E.5 2002 Cased Pipe Survey Results

Figures E.6, E.7 and Table E.8 show the cased piping inspection activity level over the last 6 years. As can been seen in the graphic, the activity level has been fairly consistent since 1999, delivering approximately 280 cased pipe inspections per year.

The total inventory of ~1400 pipe segments consists of cased road and animal crossings for well and flow lines which are in active service, it does not include abandoned or out of service pipe segments. It is anticipated by year-end 2003 all in-service cased piping segments will have been examined. However, some level of activity, to include monitoring or repeat examinations and possibly excavation, will continue into future years.

Electrical Pulse inspection technique had an increase in the number of significant anomalies reported in 2002 against the historical average. These anomalies are thought to be a result of the service provider making changes to the procedures and analysis methods employed in 2002. The provider of the Electrical Pulse technology has acknowledged the potential increase in false-positive indications reported in 2002 and is working to improve the analysis and identification of electromagnetic anomalies that are associated with corrosion. Each of these anomalies will be re-examined using guided wave and/or re-employment of electrical pulse inspection in order to verify the presence or otherwise pipe wall loss of an active corrosion mechanism.

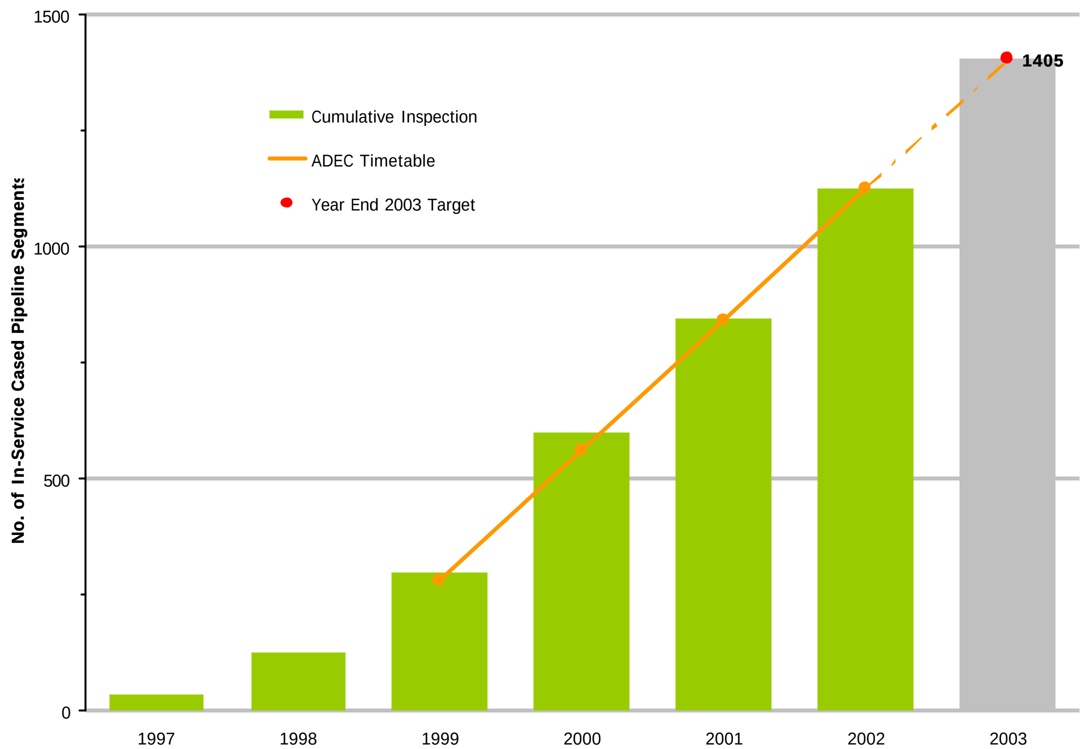

Figure E.6 Cumulative Cased Pipe Inspection Activity from 1997 to 2002

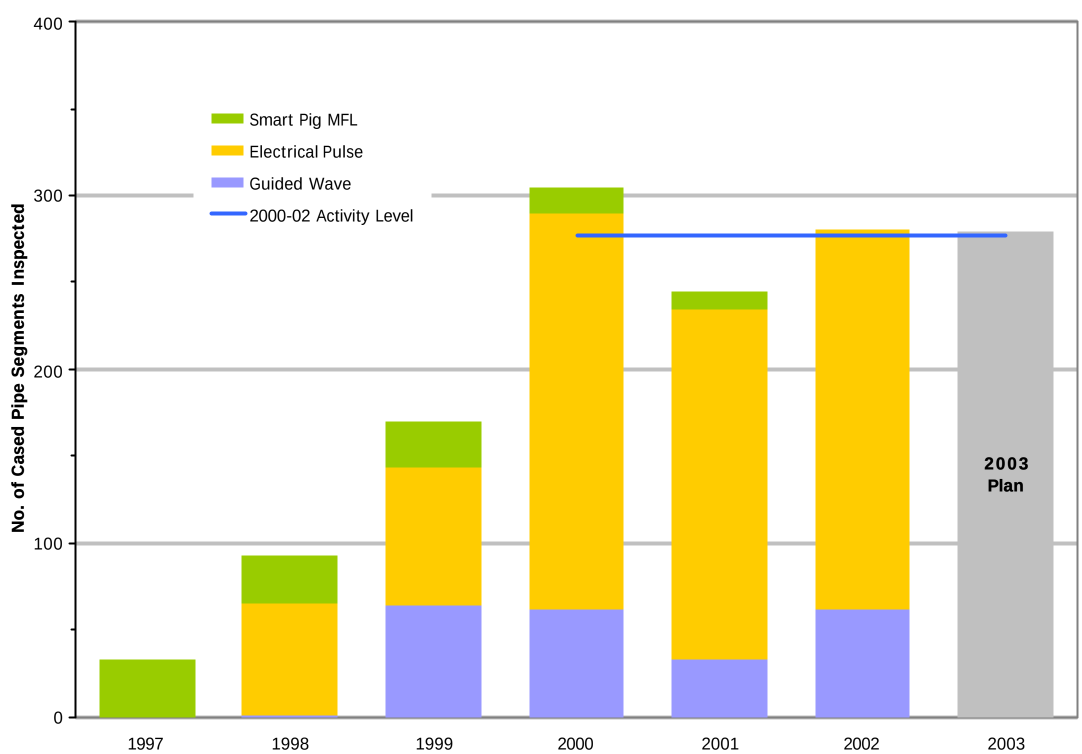

Figure E.7 Cased Piping Inspection History by Detection Method

Method	1997	1998	1999	2000	2001	2002
Guided Wave	-	1	64	62	33	62
Electrical Pulse	-	64	80	228	202	218
Smart Pig (MFL)	33	28	26	15	10	-
Total	**33**	**93**	**170**	**305**	**245**	**280**

Table E.8 Cumulative Cased Pipe Inspection Activity from 1997 to 2002

In summary, the cased piping survey activity level has been consistent over the last 5 years with the commitment to deliver a base line survey by year-end 2003. The cased piping inventory has been inspected using a number of different techniques including guided wave, electrical pulse, and MFL smart pigging. The 2003 program is expected to be at the same level as 2002 at approximately 280 cased pipe segments for the year. It should be noted that having completed the base line survey the intent for future years, 2004 and beyond, is to move the program to the next phase consisting of repeat examinations and monitoring.

Section E.1.3 Excavation History

There have been 25 cased pipeline segments at road and/or animal crossings excavated over the last 10 years at GPB. Of the 25 excavations, 1 was as a result of loss of pressure containment, the remaining 24 excavations resulted from inspection observations.

Table E.19, at the end of Section E, shows that 20 of the segments excavated were found with corrosion damage and 4 were found with no corrosion damage. The identification of potential damage areas through the inspection program and subsequent actions of monitoring and/or excavation, gives confidence that even pipe segments that our for the most part inaccessible, can be effectively managed to minimize loss as a result corrosion degradation.

Section E.1.4 External Program Summary

In summary, the level of activity directed at external corrosion has been relatively constant between 1996 and 2001 at approximately 13,000 locations per year. However, through the review process it was recognized that there was a potential that the level of risk of failure could increase as the field ages and therefore the GPB partners have decided to fund an additional level of inspection for 2002 and 2003. The activity level for 2002 was considerably greater than prior years at approximately 43,000 inspection locations. The activity level for 2003 is expected to be 35,000 inspections.

The cased piping program is on-track to complete the initial base line survey by year-end 2003. At this time the program will move into a new phase of monitoring, corrective action and repair.

Section E.2 Internal inspection

Section E.2.1 Internal Inspection Program – Scope and Results

This section summarizes the scope and results of the internal corrosion inspection program. The detailed objectives for the inspection program are given in Table B.11 and are summarized in Table E.9.

CRM	**Corrosion Rate Monitoring** Detection of active corrosion in the production and injection system in support of the corrosion mitigation and management programs
ERM	**Erosion Rate Monitoring** Similar to the CRM program but in support of the erosion management and velocity management programs
FIP	**Frequent Inspection Program** The aim of this program is to manage the mechanical integrity of locations which have significant damage based on proximity to repair criteria and/or unusually high corrosion rate
CIP	**Comprehensive Inspection Program** An annual program aimed at detecting new corrosion mechanisms by examining new locations, searching for damaged locations under known mechanisms and the monitoring of known damaged locations

Table E.9 Internal Inspection Programs

The results presented are the aggregate of the data obtained for all of these programs for flow lines and well lines. The results of the inspection program are presented in terms of the number of locations that showed an increase in corrosion damage since the last inspection as a percentage of the total number of repeat inspections,

$$\%\ \text{Increases} = \frac{\text{Locations with active corrosion}}{\text{Total \# of reinspected locations}} \times 100$$

The percentage increases is therefore a high level measure of the amount of active corrosion in any given system.

Figure E.10 shows the percentage of inspection increases (%I's) and the number of inspections per year for the flow lines broken out by 3-phase production (OIL) and water injection (seawater and produced water) service.

UT is considered the most appropriate for wall thickness determination for the large diameter water pipe work. Because of internal fluid density the sensitivity of RT is too low to accurately access corrosion increases. The damage is detectable by RT, but because of the relatively short inspection interval the change in wall thickness or corrosion rate is difficult to access. UT provides the sensitivity for a shorter inspection interval than does RT.

The percentage of inspection increases in the 3-phase system has declined considerably from 1997 to 2002. There was a slight increase in the %I's in 2001 and 2002 on flow lines compared to 2000, which reflects the increase in corrosion rates detected in the coupon monitoring program during 2000. But, because the inspection program is a lagging indicator of corrosion control, given the decline in average corrosion rates in 2001 and 2002 realized through the monitoring data, it is expected that the percentage of inspection increases will decrease in 2003. The long-term response of the inspection program compared with the monitoring program is a result of the longer time base on which this program is typically completed.

The increased corrosion activity in the water injection system reflects the increasing corrosion trends already discussed in the corrosion monitoring section. As noted, there is a strong corrective action plan in place to address the corrosion in the water injection system and it is expected that the increase in corrosion activity shown in the 2001 and 2002 inspection data will be reduced in 2003.

Figure E.11 shows the inspection increases trend and the number of inspections per year for the well lines.

For the 3-phase well lines in the long term, there is a decrease in corrosion activity as measured by the percentage of inspection increases. This is the same trend as seen in the flow lines. In the short term, however, the slight increase in corrosion activity seen in the flow lines is not reflected in the well line data although this minor discrepancy is not considered significant.

For the water system, corrosion activity is seen to be declining from 1995 through 2000. However, as with the flow lines, there has been an increase in activity in the well line data.

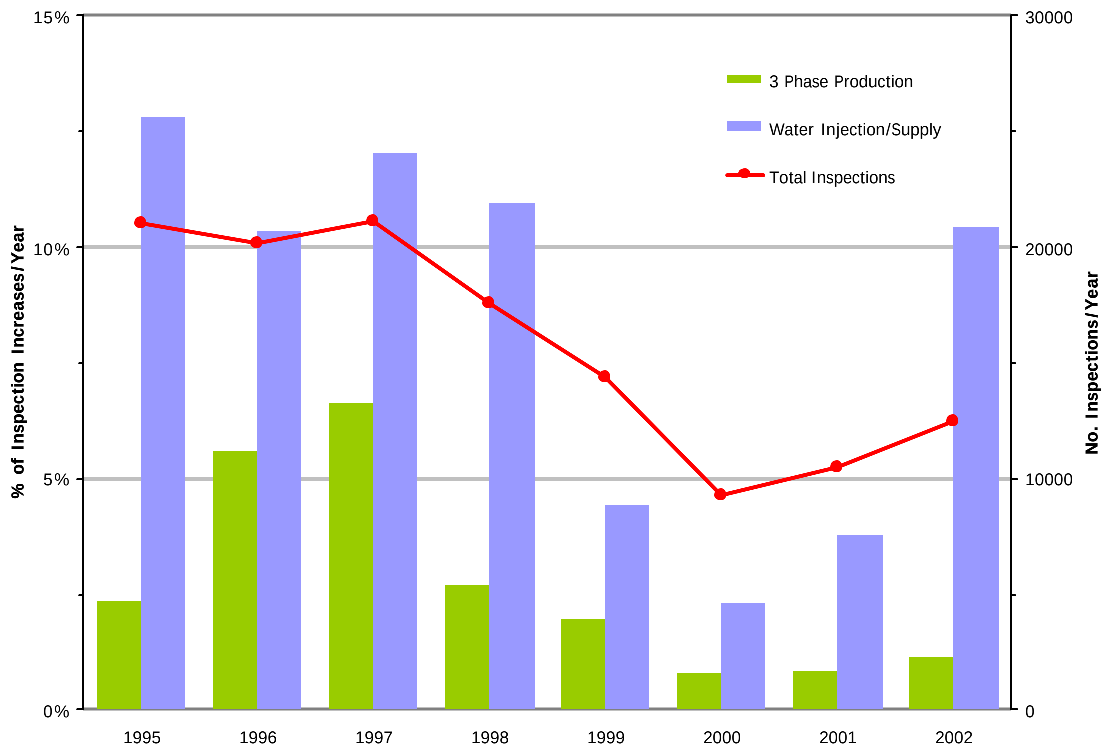

Figure E.10 Flow Line Internal Inspection Increase by Service

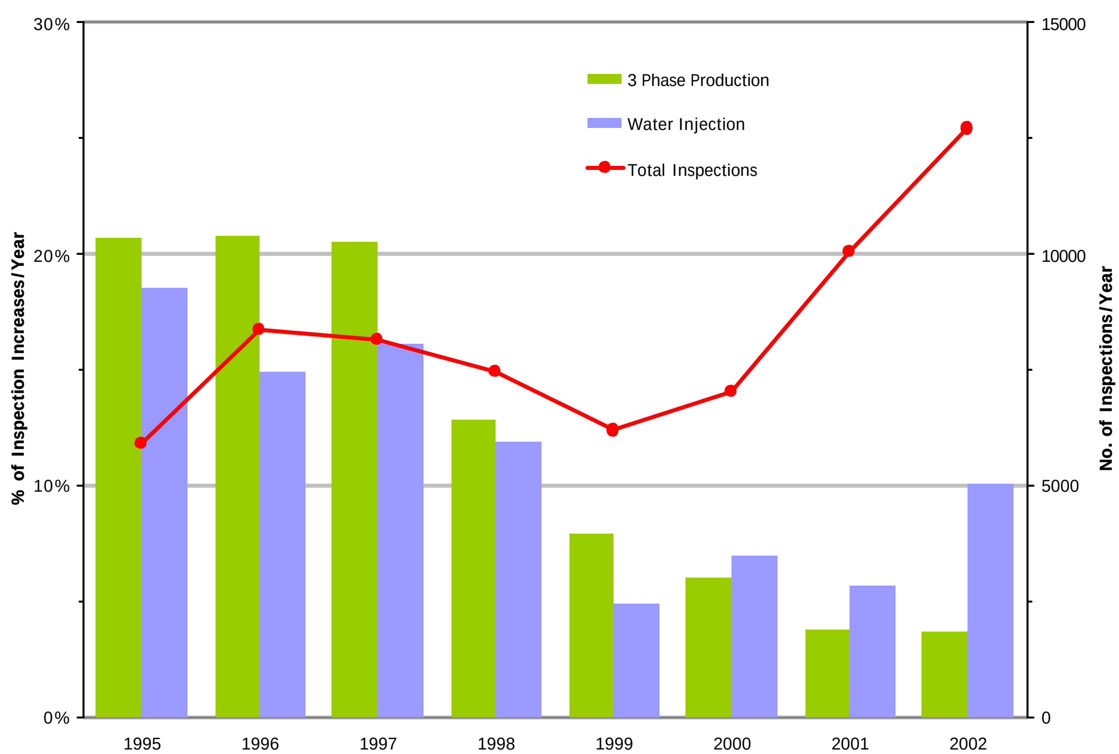

Figure E.11 Well Line Internal Inspection Increase by Service

In summary, the long term trends in the for the 3-phase production system are very similar for both the flow lines and the well lines. In each case the level of corrosion activity has dropped dramatically from the mid-1990's to the levels which have been seen over the last two years. In the water systems, again, there is significant correlation between the trends in the flow lines and those in the well lines. In each case, the level of corrosion activity has fallen from the mid-1990's through 2000/2001. However, since 2001 there has been an increase in the level of corrosion activity in the seawater system as discussed in detail in Section C Corrosion Monitoring.

Section E.2.2 Internal Inspection Intervals

This Section describes the criteria used to determine the frequency of inspection. Many factors determine the interval between successive inspections. The over-riding factor in determining inspection intervals is the purpose of inspection based on a combination of equipment condition, corrosion rate, and operating environment. The internal inspection program is sub-divided into four elements, each with a separate purpose and therefore frequency of inspection.

CRM – Corrosion Rate Monitoring: The goal of this program is to detect active corrosion in support of corrosion control activities, primarily the chemical inhibition program. The data is complimentary to other monitoring data, such as corrosion probes and corrosion coupons. As the primary aim is to determine when corrosion occurs, this program is of fixed scope at fixed inspection intervals. For a typical cross-country pipeline, the CRM program includes up to 40 inspection locations which include examples of all locations susceptible to corrosion, such as elbows, girth welds, long seam welds, bottom of lines sections, etc. These locations are each inspected twice per year. The inspections are staggered, with half the set being completed in the 1st calendar quarter and half in the 2nd. These are repeated in the 3rd and 4th quarters, respectively. Therefore, information regarding the level of active corrosion (or lack of) in a pipeline is generated every 3 months. The CRM program covers all cross-country pipelines in corrosive service.

ERM – Erosion Rate Monitoring: The purpose of this program is similar to the CRM but is aimed at monitoring erosion activity. As this damage mechanism is driven by production variables, i.e. production rates and solids loading, it is driven by 'triggers', such as velocity limits, well work, etc. If such triggers are exceeded, inspections are performed on a monthly to quarterly basis until confidence is gained that erosion is not occurring.

FIP – Frequent Inspection Program: The aim of this program is to manage mechanical integrity at locations where significant corrosion damage is detected.

Locations are added to the FIP if they are approaching repair or derate criteria or if unusually high corrosion or erosion rates are detected. As the name implies, inspections are performed frequently until the item is repaired, replaced, derated, taken out of service, or corrosion/erosion rates reduced. The inspection interval varies, depending on how close the location is to repair/derate and the rate of corrosion but does not exceed 1 year. All equipment is covered by the FIP.

CIP – Comprehensive Integrity Program: This is an annual program and is aimed at detecting new corrosion mechanisms and new locations of corrosion as well as monitoring damage at known locations. The CIP therefore provides an assessment of the extent of degradation and the fitness-for-service. All equipment is covered by the CIP, although not all equipment is inspected annually.

The scope of the internal inspection program is relatively constant at approximately 60,000 inspection items per year. This includes both field and facility inspections.

Section E.3 Fitness for Service Assessment

The basic fitness-for-service criterion used by BP is ANSI/ASME B31G. The base document is the modified B31G, PRC 3-805, which is augmented with additional requirements defined in BP specification SPC-PP-00090, “Evaluation and Repair of Corroded Piping Systems".

Figure E.12 (a) and E.12 (b) summarizes the dependence of Maximum Allowable Operating Pressure (MAOP) with the remaining wall thickness of a section of flowline based on ANSI/ASME B31G. The example and discussion below is for a typical cross-country 24" diameter low-pressure (LP) flowline. The same ANSI/ASME B31G criteria are applied to remaining flow and well lines with the appropriate characteristics and parameters substituted from the example below.

Figure E.12 and the subsequent explanation are intended to show the multiple-layers of protection to the environment provided by the current fitness-for-service criteria. At the original wall thickness of 375 mils, a typical flow line has a B31G calculated MAOP of ~1400 psi. As the wall thickness is reduced by corrosion, this pressure containment capacity is reduced.

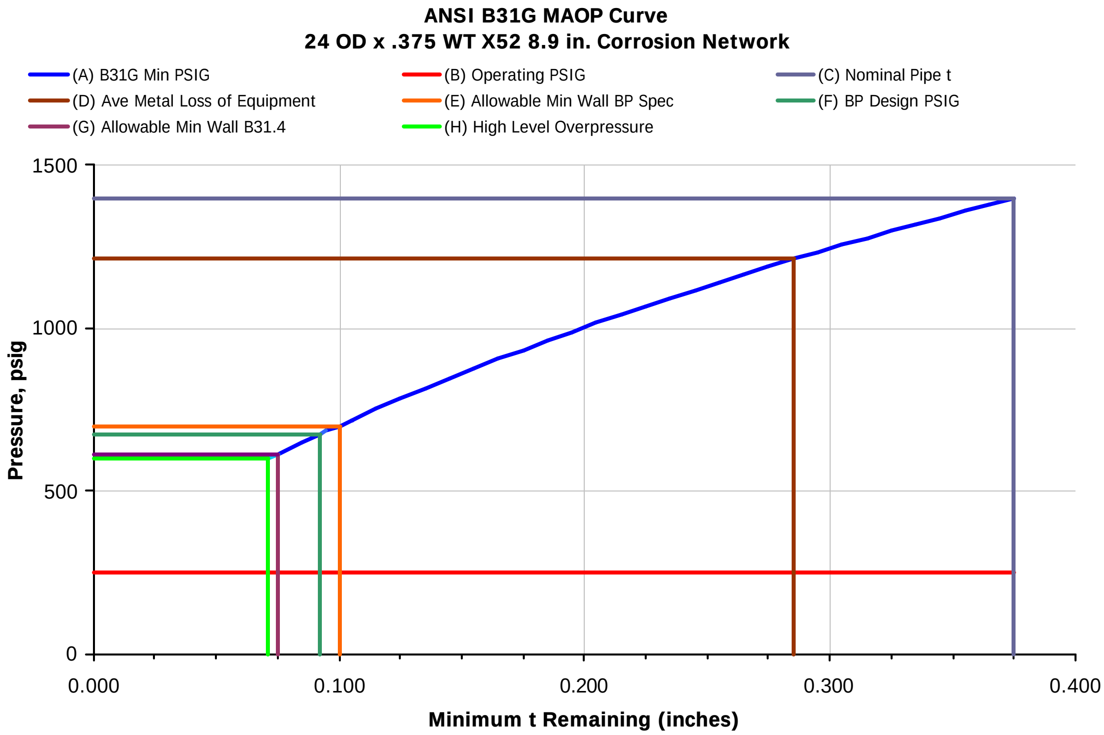

Figure E.12 (a) MAOP versus Remaining Wall Thickness

	Legend	Description/Comments
(A)	B31G Min PSIG	The relationship between maximum allowable operating pressure, MAOP, as given by B31G and the remaining wall thickness
(B)	Operating PSIG	The normal operating pressure for a typical low pressure common line or flowline (CL/LDF)
(C)	Nominal Pipe t	The original nominal pipe wall thickness which for this example is 0.375" (375 mils) as is the case for many of the flow lines at GPB
(D)	Ave metal loss	From the inspection data an average pit depth or depth of damage across the field for the 24" LP OIL flow lines
(E)	Min Wall BP Spec	The minimum wall thickness, 0.100", which is permitted under BP specification SPC-PP-00090 for the management of corroded pipework. Any location at or below this level is actioned regardless of the calculated MAOP
(F)	BP Design PSIG	The original design pressure that the pipe wall thickness was designed to retain
(G)	Allowable Min Wall	Allowable minimum wall thickness under B31 below which a repair is mandated by code
(H)	High level P protection	High level over-pressure protection for the LP systems as either a pressure switch or the PSV's on the separator/slugcatcher

Figure E.12 (b) MAOP versus Remaining Wall Thickness – Legend

Table E.13 shows the MAOP for various wall thicknesses starting from the original installed wall thickness of 375 mils. From Figure E.12 and Table E.13, it can be seen that the repair criterion used provide a significant level of conservatism over the minimum wall thickness required to retain the maximum operating pressure. In addition, high-level over-pressure protection provides additional protection over the normal operating pressure.

Step	t, mils	MAOP	Curve	Description
1	375	1395	(C)	As constructed pipe condition with no corrosion or degradation of wall thickness
2	285	1209	(D)	After 25+ years of service the average wall loss for the flow line system is 24% or 90 mils and has a MAOP of 1209 psi. This is an equivalent corrosion rate of ~4 mpy. At the average corrosion rate seen to date, in approximately 50 years the wall loss will be such that it reaches the repair criteria in Step 3. Note that the target corrosion rate is 2 mpy to provide additional protection and scope for extended field life.
3	100	700	(E)	The BP repair criterion from BP Specification SPC-PP-00090 is 100 mils with an MAOP of 700 psi. This repair criterion is 25 psi above the design pressure and 25 mils or 33% above minimum wall thickness defined by code B31G giving significant level of additional protection
4	95	675	(F)	The original system design pressure
5	75	614	(G)	The minimum wall thickness allowed under B31G for this application which is 80% wall loss regardless of pressure
6	71	600	(H)	High level over-pressure protection for the low pressure production system at Greater Prudhoe Bay
7		250	(B)	The normal operating pressure for the system

Table E.13 Thickness, MAOP Correlation

The fitness-for-service example illustrated above is for a 24" diameter low-pressure flow line. For this system the average depth of damage for cross-country oil line is approximately 24% or 90 mils and average corrosion network length of 8.9". In calculating the corrosion rate to achieve this depth of damage, it was assumed that the corrosion had happened since the beginning of field life in 1977.

Section E.3.1 FFS Interaction Between Length and Depth

In addition to the depth of damage discussed, there are a number of other considerations that have to be accounted for when assessing fitness-for-service. Some of the concerns are,

Localized/Pitting Corrosion Localized/pitting corrosion consisting of clearly defined relatively isolated regions of metal loss. The axial and circumferential extent of such regions needs to be determined and any potential areas of interaction where there is axial overlap in the extent of corrosion damage needs to be determined.

General/Uniform Corrosion General corrosion consisting of widespread corrosion between islands of original material, again, as with pitting corrosion, the axial and circumferential extent of such regions need to be determined. The limits of the extent of damage being determined by the boundaries of good or non-corroded material surrounding the damaged area.

Interaction If more than one areas of metal loss exist in close proximity, the possible interaction between these corroded areas needs to be considered. The worst case for interaction of several corroded areas is that a composite of all the profiles within a given metal-loss area needs to be considered.

Critical Dimensions The critical dimensions of metal loss, whether internal or external corrosion damage, need to be determined depending on the corrosion damage morphology described above. The most important dimensions being, the axial or longitudinal length, and the maximum depth of damage.

Evaluation of Corroded Pipe The evaluation of corroded pipe involves determining the remaining strength and safe operating pressure on the basis of the overall axial length, circumferential extent, and maximum depth of the corroded area.

Figure E.14 illustrates the FFS envelop for a combination of depth and length of defect as defined in BP Specification SPC-PP-00090. As can be seen from the curve, the criteria for allowable operating service condition is more conservative than the industry standard at the low end of the remaining wall thickness. This conservatism reflects two issues, (a) the need to provide a margin for error in the determination of wall thickness and corrosion rate, and hence remaining life, and (b) the decreased accuracy of the NDE techniques in use at a wall thickness of less 100 mils.

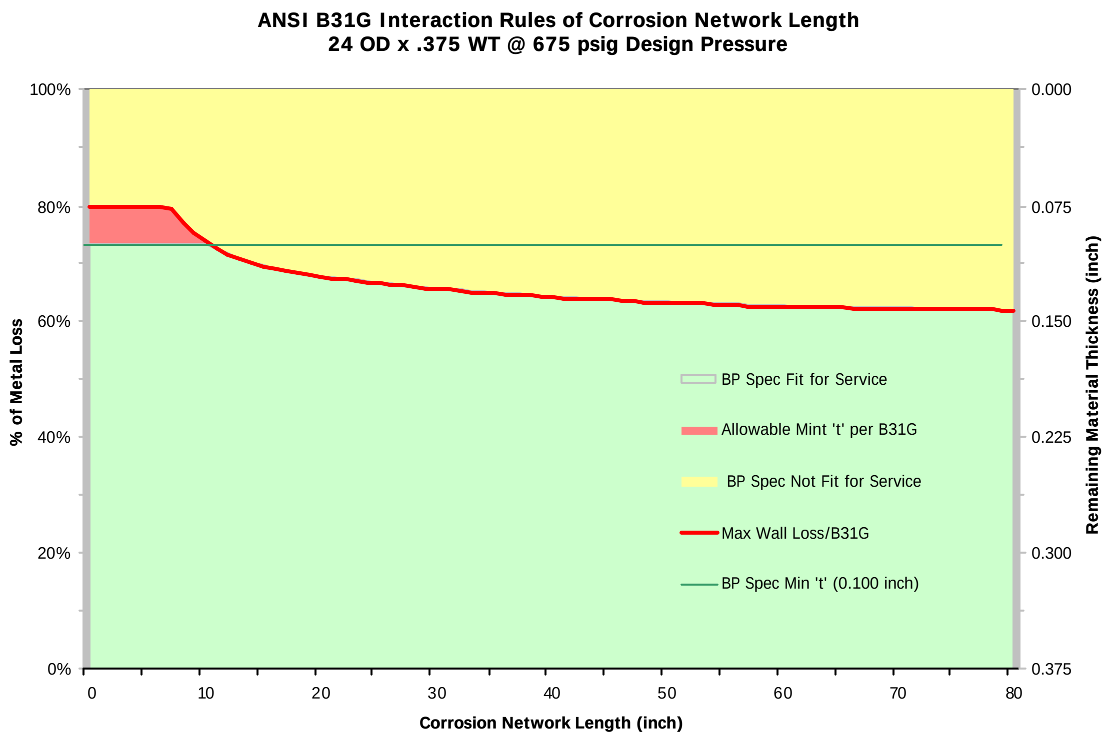

Figure E.14 Fitness-for-Service Envelope Based on BP SPC-PP-00090

In addition, repairs are typically scheduled when the corrosion damage has reached 105% of the repair criteria. This additional conservatism is in order to allow repairs to be planned rather than requiring an immediate plant shutdown.

In summary, the current equipment FFS assessment for piping accounts for two major elements,

(1) Remaining strength of material is sufficient to contain internal pressure as calculated by ANSI/ASME B31G/modified B31G methodology,

and

(2) Minimum thickness, regardless of pressure retaining calculation, equal to or greater than 0.100 inch,

whichever is the greater remaining wall thickness of the two assessment criteria.

Section E.4 Correlation Between Inspection and Corrosion Monitoring[7]

As noted in Table B.12, inspection and corrosion monitoring have different characteristics; in particular, inspection techniques are comparatively insensitive but are the most accurate as they measure actual wall loss. In contrast, corrosion monitoring is more sensitive but less accurate as a measure of corrosion rate as the weight loss coupon is not an integral part of the pipe wall.

Therefore, in order to have good confidence in the results from the corrosion-monitoring program, it is necessary to show a correlation between the chosen monitoring program and the results of the inspection program. The following section describes the correlation between inspection and monitoring programs for the 3-phase production system.

Figure E.15 shows the trend in average corrosion rate from weight loss coupons and the percentage of increases found in the inspection program. It should be noted that the inspection results included in the analysis are not the full data set but has been refined to include only that data which has an inspection interval (time since last inspection) of less than 730 days (two years). Also, the indicated reporting year in Figure E.15 has been changed to reflect the mid-point of the inspection interval rather than the time of inspection as in the other figures in this report. This change in the reporting time compensates for the fact that corrosion is occurring over the entire time interval between inspections. Similarly, the weight loss coupon corrosion rates are reported as the mid-point of the exposure period not the removal date.

Figure E.15 also shows that the same trend of reducing corrosion activity is seen in both the inspection results and corrosion monitoring data.

From the correlation between inspection and corrosion monitoring, a number of important conclusions can be drawn,

- As the corrosion rates decrease as a result of the effectiveness of the inhibition program, then further program optimization will be driven by the information gained from the corrosion monitoring program rather than the inspection program
- Timely optimization of the chemical program can not be reliant on feedback from the inspection data but must be managed through the corrosion monitoring program

[7] In addition to Charter Work Plan, this information supplied to provide additional context and help in understanding BP corrosion management activities

- Because of the lower sensitivity of the techniques used in the inspection program, the corrosion rates in the 3-phase flow lines are below the detection limits for inspection; therefore corrosion rate monitoring becomes a function of the coupon program leaving inspection as a confirmation and integrity assessment tool

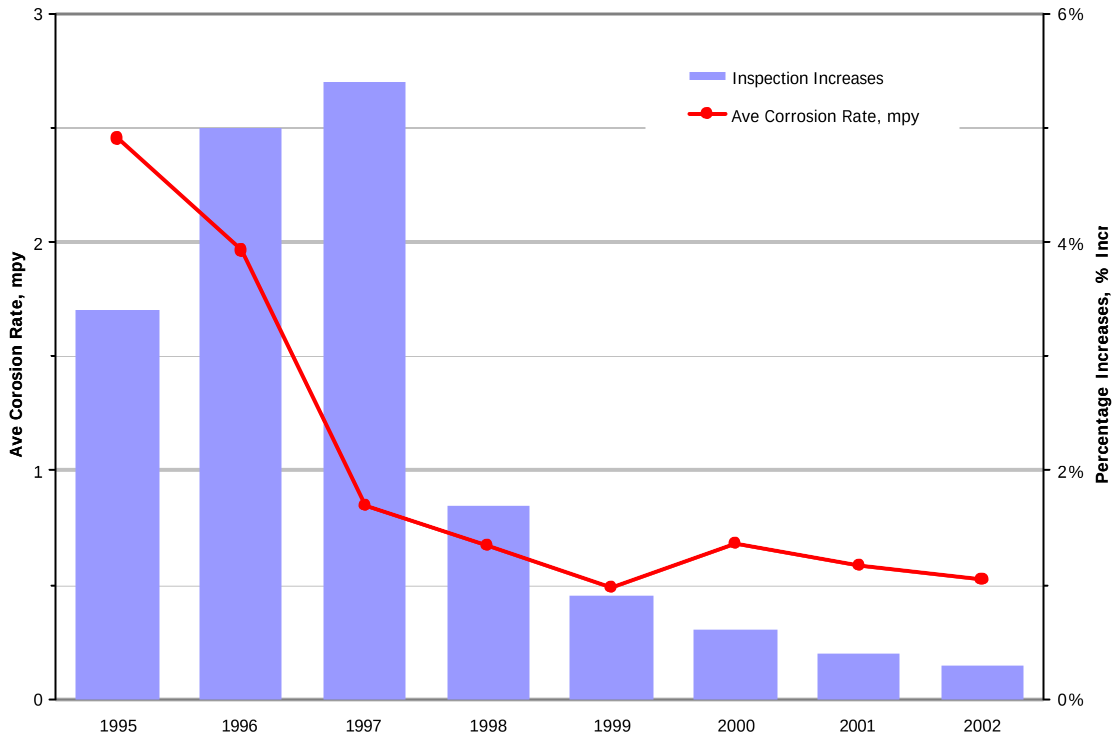

Figure E.15 Correlation of Corrosion Rate and %Increases

The data in Figure E.15 demonstrates the correlation between the corrosion monitoring and the inspection data for the 3-phase production system. A similar degree of correlation exists between the corrosion monitoring and the inspection data for the water injection systems. Figures E.10 and E.11 show increasing corrosion activity in both the flow lines and well lines for the water system which is also reflected in the corrosion monitoring data depicted in Figures C.12 and C.13.

In summary, the data in this section clearly shows that corrosion rates as determined by both inspection and corrosion-monitoring techniques are falling and that the corrosion management plan for internal corrosion in 3-phase production service is effective. Furthermore, the correlation between the inspection data and the corrosion monitoring data allows the corrosion monitoring data to be used with confidence to manage the chemical treatment program in a timelier manner.

Section E.5 Smart Pigging

Smart pigs or instrumented in-line inspection tools are used by exception at GPB where pigging facilities and process environment allow for technical and cost effective performance within the capabilities of the instruments. Magnetic flux leakage (MFL) type tools are the most commonly used by BP on the North Slope.

It is important to note that because the vast majority of the cross-country flow lines are above ground, the value of smart pigging is considerably lessened compared to buried or underground systems. The primary value for GPB is in the initial identification and location of damaged locations within a pipeline system. Having initially identified the location of damaged areas, the long-term integrity, pipeline condition and current corrosion rate, of the flowline can be much more effectively managed through the use of targeted manual NDE techniques.

As a consequence, smart pigging is used at GPB to initially establish the condition and location of corrosion damage in lines at risk. Having established the condition and location of damaged sections of line the locations are then added to the routine NDE program where the condition and hence immediate fitness for service is determined and where the on-going corrosion rate and level of corrosion mitigation can be monitored.

It should also be noted that there are some limitations with the capabilities of the smart pig technology currently available. A typical high resolution[8] MFL smart pig gives wall thickness measurements that are ±10% of the wall thickness and sizing resolution of 3 times wall thickness for length and width assessment. In addition, there are temperature and pressure limitations that prevent or make difficult the use of MFL tools in many lines at GPB. The typical upper operating temperature for the MFL tools is 122°F/50°C compared with a typical separator fluids temperature of 150-160°F.

While the smart pig program is an important element in the overall corrosion and integrity management program, it should be considered like any other inspection or monitoring technique as simply another tool to be applied where it delivers the most value.

When used, smart pig inspections are performed to gain a relative understanding of pipeline condition and rate of deterioration and/or to provide confidence that

[8] MFL manufacturer technical data sheet

the internal and external conventional inspection programs have identified locations where mechanical integrity is at risk. Because MFL tools do not directly measure pipeline condition, results from in-line inspections are not reported in as received from the smart pig service company but are reported as part of the NDE summary in Section E.

Areas identified by smart pigging and interpreted as being a risk to future operation of equipment, are proofed through visual, radiographic and/or ultrasonic inspection techniques and the results of the verifications are reported through routine inspection programs.

In 2002 three produced water flow lines were examined by smart pig (MFL) inspection. These lines have not previously been subject to smart pig examination, summarized in Table E.16.

Equipment	Service	Diameter	From	To	Length (ft)
03-PWI	PW	12"	FS-2	DS-03	15521'
04-PWI	PW	12"	FS-2	DS-03	7077'
09-SWI	PW	12"	FS-2	DS-09	16882'

Table E.16 2002 Completed Smart Pig Assessments

The majority of the metal loss features reported in each of the lines smart pigged in 2002 were external corrosion locations. There were no areas reported where the pipeline did not meet the fit-for-service criteria for the equipment. Proofing examinations by ultrasonic inspection has been completed on the severest reported anomalies and the results are included in the aggregate data from 2002. Additional follow-up of the reported features is an ongoing part of the normal radiographic and ultrasonic NDE activity at GPB.

Table E.17 below shows the historical level of smart pigging activity at GPB

Type	92	93	94	95	96	97	98	99	00	01	02
MFL	11	-	6	14	1	6	3	6	5	3	3
UT	12	9	-	-	-	-	-	-	-	-	-
Total	23	9	6	14	1	6	3	6	5	3	3

Table E.17 Smart Pig Activity 1992 to 2002

Figure E.18 shows the smart pig activity level from 1992 through 2002. As can be seen from the chart, the level of activity has fallen from a high of 25 runs per year in 1992 to the 3 runs completed in 2002. In addition to the smart pigging activity level, the chart also shows the average corrosion rate for the oil service flows lines. The reduction in smart pigging activity level coincides with the decline in corrosion rate and reflects the change in emphasis of the program. As the corrosion rates have fallen, then the immediate concern of the program has shifted from the short-term integrity of the flowline, which is focused on condition, to the long-term integrity of the flow line, which has a dual focus of condition and corrosion rate. This long-term integrity is better managed through higher resolution methods such as corrosion monitoring and manual radiographic and ultrasonic NDE.

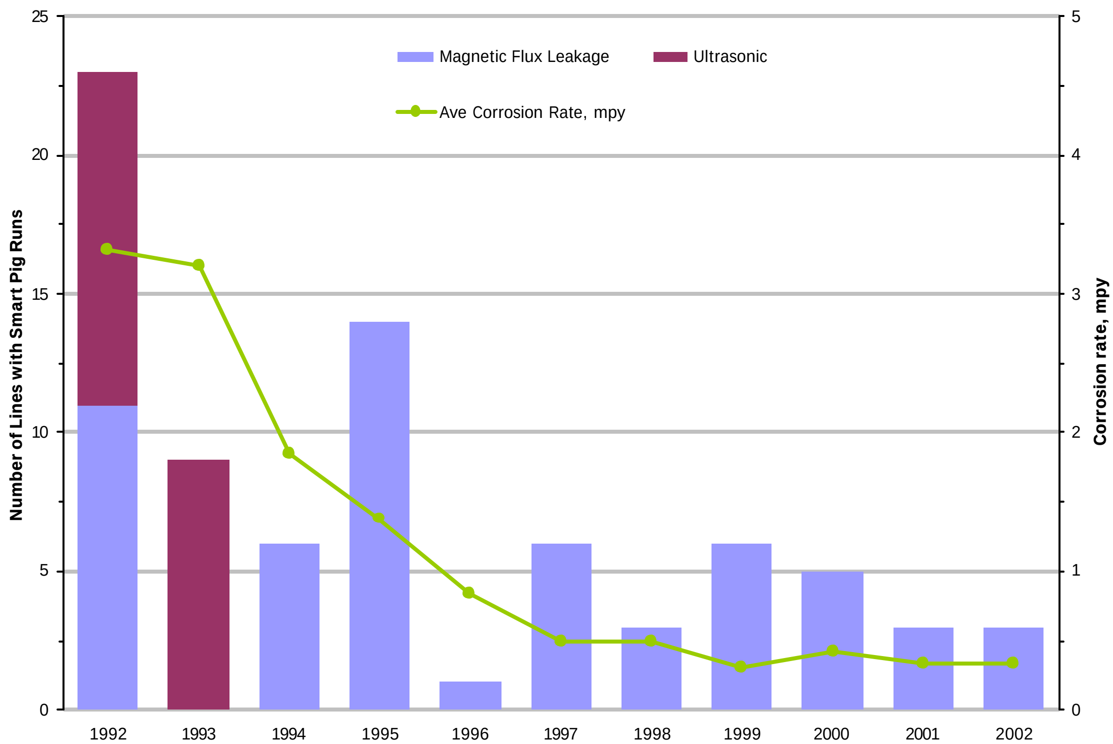

Figure E.18 Smart Pig Activity and Corrosion Rate 1992 to 2002

In summary, while smart pigging is an important tool to have available in the management of the long term integrity of the flow lines, it is not always the most appropriate or applicable for GPB because of the operating conditions, design and accessibility of the pipelines to precision manual methods of NDE.

Section E.6 Inspection Summary

In summary, the main conclusions from the inspection section are,

- The external corrosion inspection program, at ~43,000 items, for 2002 was significantly above the historical average. Of the 43,000 items, approximately 2½% showed damage, which is less than prior years.

- The 2003 external corrosion program is planned to be about 35,000 items, which is again is substantially higher than the average activity level from 1995 through 2001.
- The cased piping survey is on-track to complete the initial baseline survey by year-end 2003 as agreed with ADEC.
- A unified internal inspection philosophy and program structure has been implemented across GPB with a total program size of approximately 60,000 items.
- The inspection results for both the flow line and well line 3-phase systems show improved performance in the long term. In the short term there is a slight increase in the corrosion activity on the flow lines. This is expected to be reversed following the trend in the corrosion coupon program as a result of the better performance of the corrosion inhibitor.
- The water injection systems show a long term improving trend. However, there is an increase in the corrosion activity in the short term and, as discussed in Section C, corrective actions have been put in place in the sea water system and additional inhibition has been added in 2002 to the produced water system.
- The inspection interval and fitness-for-service criteria, as defined by B31G, was discussed in the context of the current piping corrosion rate and piping condition.
- The results of the inspection program and the weight loss coupon program from the 3-phase oil service were shown to be strongly correlated. The reduction in corrosion activity from both measures being attributable to the implementation of an aggressive and increasing corrosion inhibition program in the 3-phase flow lines since 1995.
- A similar level of correlation was seen in the water injection system information for both inspection and corrosion monitoring.

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
1992	COTU Access Road	FS1 to FS2 12" MI Distribution	10% external wall loss	Insulation/coating/tape repair
1995	S Pad West Entrance Crossing	S Pad 24" 3 Phase Production S Pad 14" Produced Water S Pad 10" Gas Lift S Pad 8" Miscible Injection	61% external wall loss 36% int/ext wall loss 34% external Wall Loss 41% external wall loss	Sleeve/insulation/coat repair Sleeve/insulation/coat repair Insulation/coating repair Replaced segment/FBE
1995	GC1 Main Entrance	Distribution 24" Gas Lift Y Pad 24" 3 Phase Production	29% external wall loss 24% external wall loss	Insulation/coating repair Insulation/coating repair
	GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift Y Pad 24" 3 Phase Production	42% external wall loss 26% external wall loss	Sleeve/insulation/coat repair Insulation/coating repair
1996	GC-1 Spine Road	Distribution 24" Gas Lift D Pad 24" 3 Phase Production Y Pad 24" 3 Phase Production Distribution 20" Produced Water	53% external wall loss 33% external wall loss 18% external wall loss 8% external wall loss	Sleeve/insulation/coat repair Insulation/coating repair Insulation/coating repair Insulation/coating repair
	E Pad Entrance	E Pad 24" 3 Phase Production	21% external wall loss	Insulation/coating repair
	GC3 to FS3 Caribou Crossing	Distribution 24" Gas Lift	No corrosion damage	None
	FS1 to FS2 Caribou Crossing	Distribution Natural Gas 30" Sales Oil 30" Distribution 24" Gas Lift Distribution 32" Sea Water	11% external wall loss 14% external wall loss No corrosion damage No corrosion damage	Insulation/coating/tape repair Insulation/coating/tape repair None None

Table E.19 Cased Piping Excavation History

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Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
1998	S Pad East Entrance Crossing	S Pad 10" Gas Lift	~80% wall loss - ext rupture	Replaced segment
	GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift	9% external wall loss	Insulation/coating repair
	GC2 to GC1 Q Pad Rd Crossing	Distribution 34" Natural Gas	No corrosion damage	Insulation/FBE coated
2000	S Pad East Entrance Crossing	S Pad 24" 3 Phase Production S Pad 14" Produced Water S Pad 8" Miscible Injection	~60% external wall loss ~50% external wall loss 25% external wall loss	Replaced segment/coat repair Replaced segment/coat repair Sleeve/insulation/coat repair

Table E.19 (Cont.) Cased Piping Excavation History

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Section F

Repair Activities

Section F Repair Activities

The repair activities in 2002 include a total of 78 repairs as compared to 31 in year 2001. This 2½ fold increase in corrosion related repairs does not represent a large scale increase in corrosion activity across GPB, but, instead, represents some very specific actions taken to address specific concerns within the field.

Table F.1 summarizes the repair activity for the flow line and well lines for 2002.

Service	Type	Internal	External	Mechanical	Total
Oil	FL	8	35	-	43
	WL	7	11	-	18
PW	FL	1	6	-	7
	WL	1	1	-	2
SW	FL	-	-	-	-
	WL	3	-	-	3
Gas	FL	-	4	1	5
	WL	-	-	-	-
Total		20	57	1	78

Table F.1 2002 Repair Activity

Of the 78 repairs, 57 were associate with external corrosion and therefore reflect the large scale ramp-up in external corrosion inspection activity in 2002. The 2001 external inspection program of ~15,000 items resulted in 17 repairs, this compares with the 2002 inspection program of ~43,000 items which resulted in 57 repairs. The repair ratio for the 2 years is approximately the same at about 1 repair every 1000 items inspected.

The increase in internal corrosion related repairs is dominated by the increase in flow line internal corrosion repair activity. Of the 8 internal corrosion related repairs, 7 were associated with the 24" flow lines from Point McIntyre. In addition to the 7 internal repairs, an additional 25 repairs on this line were associated with external corrosion. The majority of the damage found on these flow lines did not exceed the fitness-for-service criteria defined in Section E. However, the corroded areas were repaired preemptively in order to avoid unnecessary environmental risks associated with ongoing operations due to lack of road access. As an example, 12 sleeve repairs were installed on the section of the 24" Point McIntyre flowline that crosses over the Putuligayuk River.

The three well line repairs noted for SW were in the Grind and Inject system. The Grind and Inject plant takes waste material and processes it through a ball mill prior to permitted disposal down hole. Therefore, the fluids down stream of the Grind and Inject plant are an oxygenated-slurry and the repairs on this system are unrelated to the problems being encountered else where in the seawater system.

The 78 repairs were broken down into three categories for further analysis,

- Internal – Erosion and/or corrosion metal loss
- External – External corrosion metal loss (CUI)
- Mechanical – Third party damage, fabrication defect

Figures F.2, F.3, and F.4, and Table F.5, show the 3-year trend in repairs grouped by service, damage mechanism, and equipment, respectively. The increase in repairs noted for 2002 was a result of the increased scope of the External Inspection program.

It should be noted that this summary does not include structural related remedial work that is addressed in detail in Section G.

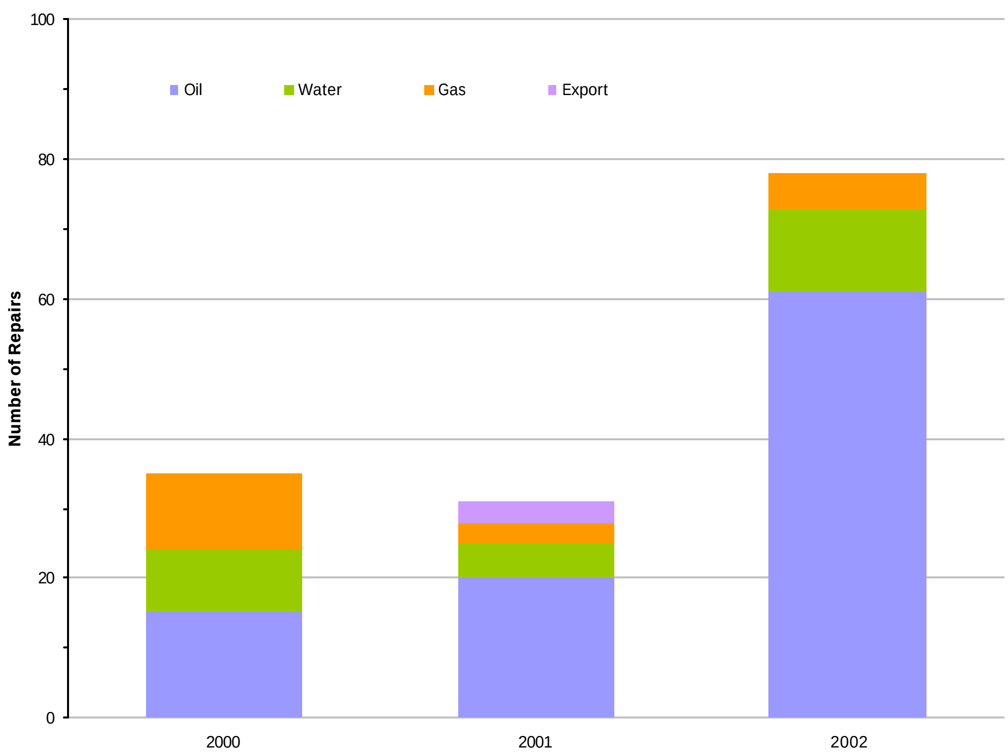

Figure F.2 Repairs by Service

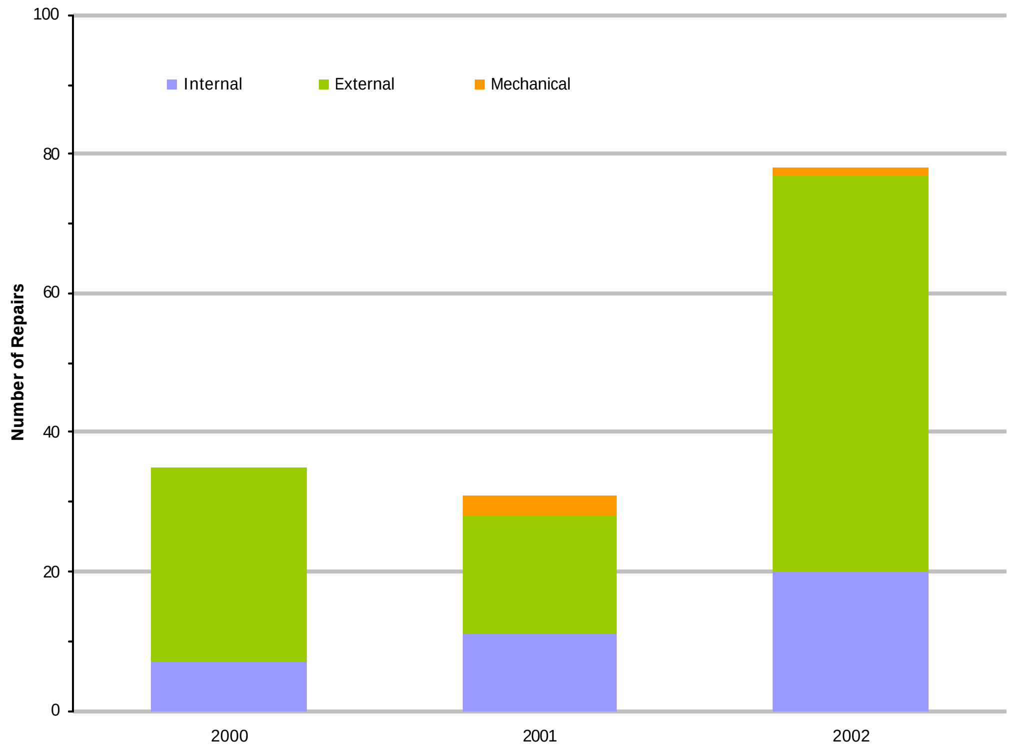

Figure F.3 Repairs by Damage Mechanism

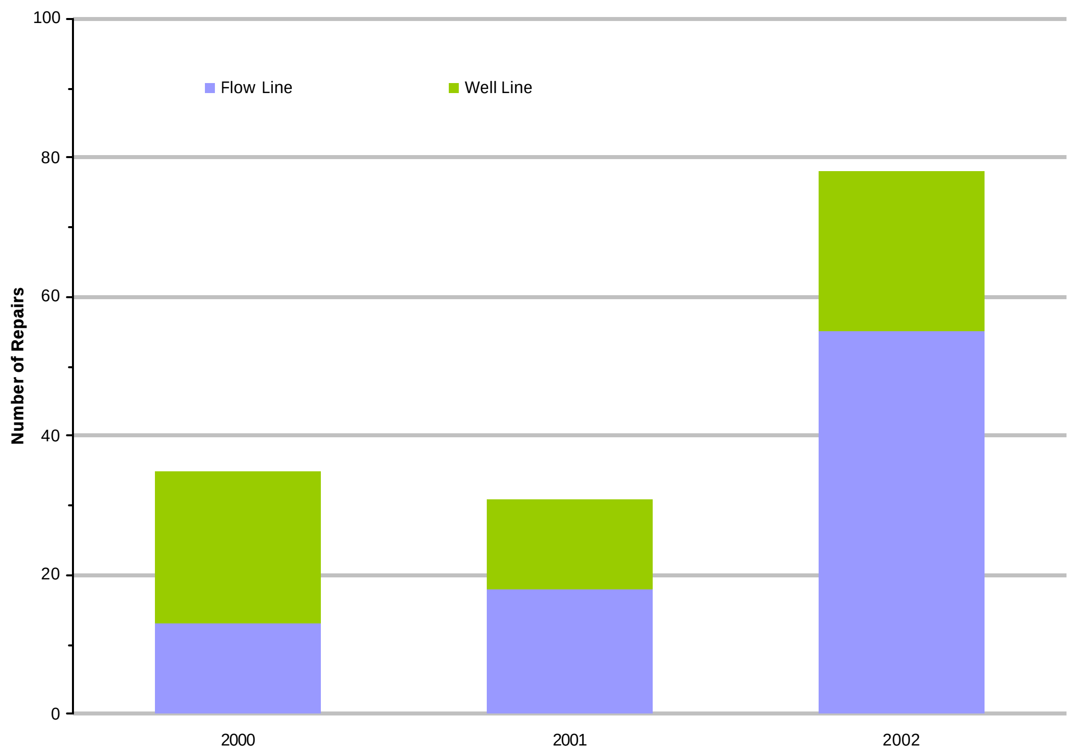

Figure F.4 Repairs by Equipment

In summary, there was a significant increase in the number of repairs in 2002 compared to 2001, 31 and 78 respectively. There were 2 main causes of this increased activity, first, the increased level of external corrosion inspection. Second, preemptive repairs on the Point McIntyre 24" flow line as a consequence of the follow-up inspection after the July 2001 leak on this system.

		2000			2001			2002						
Service	**Type**	**Int**	**Ext**	**Mech**	**Int**	**Ext**	**Mech**	**Int**	**Ext**	**Mech**	**Total**	**Int**	**Ext**	**Mech**
Oil	FL	2	1		2	7	-	8	35	-	55	12	43	-
	WL	5	7		4	5	2	7	11	-	41	16	23	2
Water	FL	-	2		1	3	-	1	6	-	13	2	11	-
	WL	-	7		1	-	-	4	1	-	13	5	8	-
Gas	FL	-	8		-	2	-	-	4	1	15	-	14	1
	WL	-	3		-	-	1	-	-	-	4	-	3	1
PO	FL	-	-		3	-	-	-	-	-	3	3	-	0
Total		**7**	**28**		**11**	**17**	**3**	**20**	**57**	**1**	**144**	**38**	**102**	**4**
Grand Total				**35**			**31**			**78**				**144**

Table F.5 Historical Repairs by Service

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Section G

Corrosion and Structural Related Spills and Incidents

Section G Corrosion and Structural Related Spills and Incidents

Section G.1 Corrosion Related Leaks

This section summarizes the corrosion and structural related incidents that occurred in 2002 and provides a historical perspective on the leaks (loss of containment) and saves (repairs before leak of non-FFS equipment).

Table G.1 summarizes the equipment, failure mechanism and volume of leaks due to corrosion that occurred in 2002. There were no structural related leaks in 2002.

Service	Location	Type	Date	Mechanism	Volume
3 phase production	F-48	S-riser	14-Jan-02	Erosion	115 gal
3 phase production	H-21	S-riser	18-April-02	Int	84 gal
3 phase production	13-12	WL	14-June-02	Ext	1 qrt
3 phase production	Z-LDF	FL	4-Oct-02	Ext	4 gal

	Surface		Service			Mechanism		
	Int	Ext	OIL	SW	PW	CO_2	Erosion	CUI
WL	2	1	3			1	1	1
FL		1	1					1

Table G.1 2001 Leaks Due to Corrosion/Erosion

Table G.2 shows the number of corrosion related leaks and saves from 1996 through 2002. The ratio of leaks to saves provides a high level measure of the performance of the inspection program at detecting severe damage before it results in a failure. A 'save' is defined as a location found via the inspection program that warrants a repair, system derate, replacement or removal from service as the equipment no longer meets the FFS criteria defined in Section E. This data is also shown in Figure G.4.

It should be noted that items are typically scheduled for repair at 105% of design pressure, to allow time to schedule and complete the repair before the item requires removal from service.

Table G.2 and Figure G.4 (a) and (b) show the number of leaks and the number of saves, plus the ratio of leak to saves. The trend in the total number of saves, locations that have reached FFS criteria, plus the number of leaks, is an approximate measure of the overall performance of the corrosion management program. The significant increase in number of saves is a direct result of the ramp-up of the External Inspection program.

Of the 4 leaks that occurred in 2002, 1 was associated with erosion, 2 with external corrosion and 1 with internal corrosion – see Table G.1.

	Flow Lines			Well Lines			Total
	Saves[1]	Leaks	$\frac{S}{(L+S)}\%$	Saves[1]	Leaks	$\frac{S}{(L+S)}\%$	$\frac{S}{(L+S)}\%$
1996	14	4	78%	57	6	90%	88%
1997	33	2	94%	73	1	99%	97%
1998	51	3	94%	34	4	89%	92%
1999	22	0	100%	25	3	89%	94%
2000	9	1	90%	54	0	98%	97%
2001	7	2	78%	21	4	84%	82%
2002	58	1	98%	23	3	89%	95%

Table G.2 Historical Corrosion Leaks and Saves

Section G.2 Structural Issues

There were no structural related pipeline failures in 2002.

A Walking Speed Survey (WSS) of the GPB east flow lines was completed in 2002. As part of the WSS, anomalies are noted and then reviewed and evaluated by the Field Mechanical Piping Engineer for action as appropriate. The Walking Speed Survey is a 5-year recurring program with the following schedule,

Year	Scheduled	Equipment Description
1	2002	GPB East Cross Country Pipelines
2	2003	GPB West Cross Country Pipelines
3	2004	GPB East Well Pads
4	2005	GPB West Well Pads
5	2006	Lisburne Cross Country Pipelines/Drill Sites

Table G.3 Structural/Walking Speed Survey Schedule

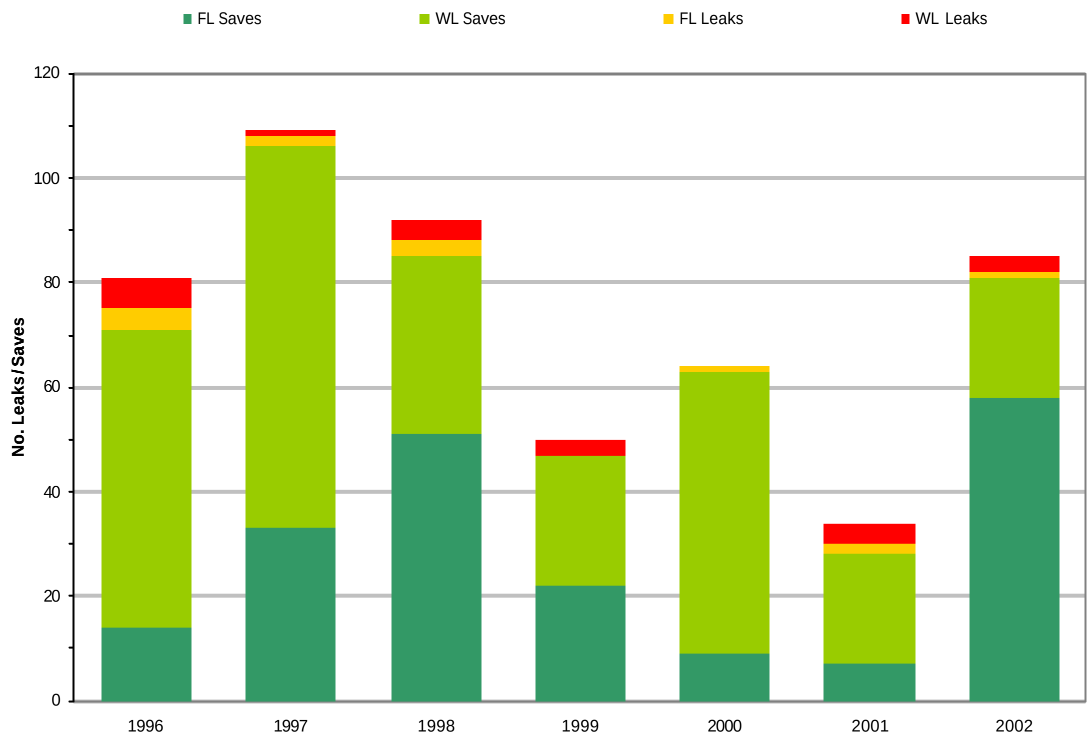


Figure G.4 (a) Historical Corrosion Leaks

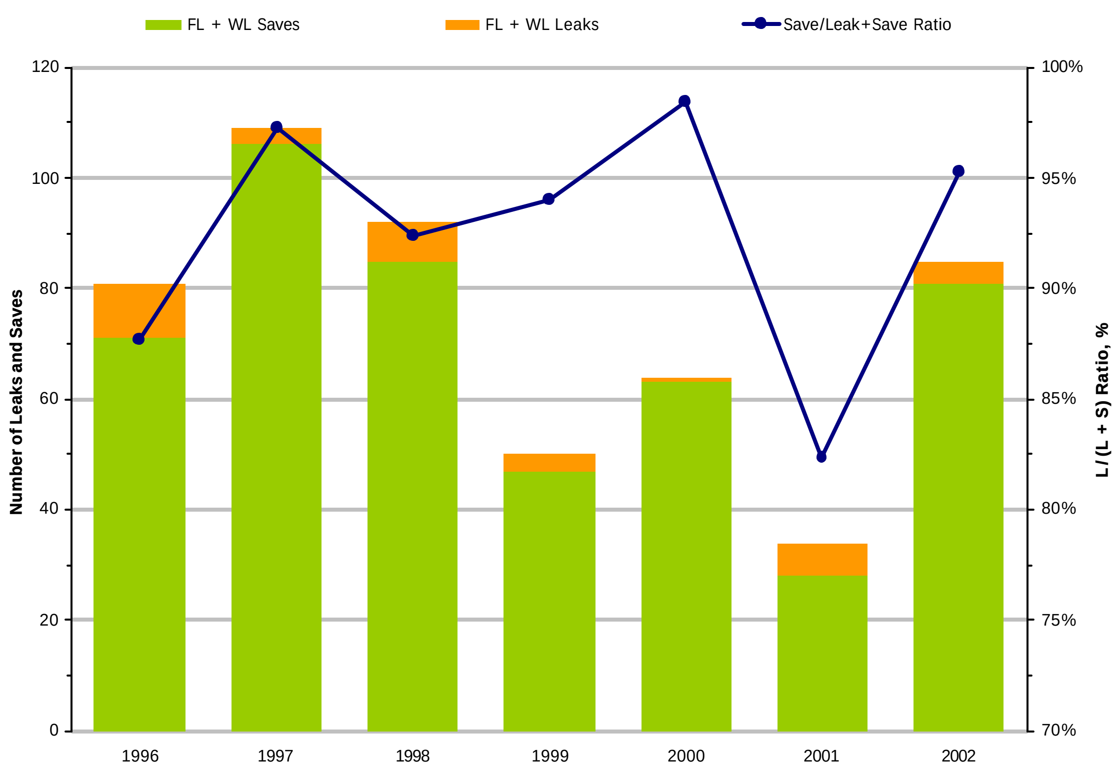


Figure G.4 (b) Historical Corrosion Leaks

Where there is perambulatory access, the Walking Speed Survey consists of a visual examination of process equipment and system components to identify mechanical integrity deficiencies. As the name implies the observations are made at 'walking speed' and are focused on, but not limited to,

- Piping and insulation
- Structural components
- Electrical equipment
- Instrumentation equipment
- Communication equipment
- Chemical injection tubing
- Pipe line road and animal crossings

Anomalies are recorded in a field report against each of these categories according to specific guidelines. The 2002 Walking Speed Survey of the east side cross-country flow lines was completed as per the schedule shown in Table G.4.

In addition to the Walking Speed Survey, there was significant work completed in 2002 to address known structural concerns,

GPB West

- Modified existing vertical support members (VSM) or installed new VSMs to correct sagging lines, repositioned saddles at A, B, D, F, H, J, N, S, Y pads
- Remediation of the M pad pipe line supports and anchors following the flooding of the Kuparuk river during break-up in 2002

GPB East

- DS-01 saddles - lines lifted to reposition in saddles and the saddles replaced onto VSMs
- DS-06 - installed new VSM
- DS14 – installed new VSMs and lines repositioned

Inspection and repairs due to structural anomalies is an ongoing program. As items are identified, each is evaluated and appropriate corrective action is initiated.

Beside the Walking Speed Survey, year round, Field Operations and Security personnel are tasked as the primary identifiers of flow lines and well lines with potential structural integrity problems. Observations of wind-induced vibration, excessive pipe movement, out-of-place pipe guides, bent piping, etc. are reported. A visual inspection by a competent engineer is first completed to determine any required action.

When evaluating possible damage caused by structural movement, i.e. subsidence, jacking, vibration, impact, slugging, snow loading, etc., the following items are considered:

- Insulation damage
- Piping damage
- Bent piping
- Piping saddles at adjacent pipe supports
- Unsupported spans
- Locations of line anchors
- Road crossings
- Expansion loops
- Branch connections

A piping stress analysis is completed as deemed necessary by the Field Mechanical Piping Engineer. Third-party piping stress analysis engineering experts may be involved as determined by the Field Mechanical Piping Engineer.

If significantly bent piping is observed, NDE inspection of the areas in question is performed. To accomplish the inspection the insulation is removed. The purpose of the inspection is to determine if any detrimental damage (i.e. wall thinning, cracks, ovality, buckling) exists. The NDE methods typically used include visual, ultrasonic, magnetic particle, radiography, and dye penetrant as appropriate. The applicable ANSI/ASME B31 piping Code acceptance limits are used to determine acceptability. BP has found by experience that the aesthetic appearance of pipes is not a conclusive sign that the pipes lack structural integrity or are not fit-for service.

When the inspections and analysis warrant action, a recommendation is provided to Operations for creation of a work order to address the location in question. An engineering design package is prepared to complete and document the work action. Management of Change and other procedures are applied as required.

In summary, structural related problems are addressed through two processes, first, is a Walking Speed Survey, which inspects piping on a 5-year cycle. Second, are the reported observations of Field and Security personnel of structural anomalies.

Section H

2003 Corrosion Monitoring and Inspection Goals

Section H 2003 Corrosion Monitoring and Inspection Goals

Section H.1 2002 Corrosion and Inspection Goals Reviewed

The introduction of single operatorship at Greater Prudhoe Bay was a significant event in 2000. Although much of the integration of the corrosion management programs was completed in 2000, a significant focus for 2002 was the completion of this activity for all aspects of the corrosion management system.

Section H.1.1 Corrosion Monitoring

The weight loss coupon program frequency remains unchanged from 2001 and is summarized in Table H.1.

Service	Flow Lines (months)	Well Lines (months)
3-phase production	3	4
Produced water	6	8
Seawater	3	3
Processed Oil	3	N/A

Table H.1 Coupon Pull Frequency

ER probes are currently located, where possible, on the major cross-country oil service flow lines at either the upstream or down steam end of the pipeline. These probes are replaced when they have reached half of the useful probe life or every year, which ever is least.

Section H.1.2 Inspection Programs

The elements of the inspection program, CRM, ERM, FIP, CIP and CUI were discussed in detail earlier in report. These programs form the foundation for the on-going inspection programs at GPB. There are no major changes to this program anticipated in 2003.

There were three smart pig runs completed in 2002. The 2003 plan is for three 24" 3-phase oil production flow lines to be smart pigged subject to the availability of the smart pig tool of the correct size and capability required for the planned pipelines.

Corrosion under insulation inspections in 2002 were significantly above the level seen in the previous 5 years and above the planned level of 35,000. The 2003 program will be of a similar size to that planned for 2002 at approximately 35,000 items. Included in this scope will be locations that have historically been difficult to access due to the lack of roads along the pipelines. These pipeline segments will be accessed via a tracked vehicle under a tundra permit and include the P-pad to Y-pad pipelines that cross the tundra and the S-pad to M-pad pipelines that cross the Kuparuk river flood plain.

The below grade cased piping inspection program for 2002 was completed with approximately 280 location inspected. The program for 2003 is of a similar size and will complete the initial 5-year inspection of all active case pipe segments at road and animal crossings.

Section H.1.3 Chemical Optimization

The rationalization and optimization of the surface inhibition program at Greater Prudhoe Bay was completed in 2001. In 2002 the primary 3-phase corrosion inhibitor was replaced in 1Q 2002 with the intent of improving the level of corrosion control in low-velocity portions of the upstream system and the in the produced water distribution network.

In 2003 there are unlikely to be any similar large-scale changes to the inhibition program. However, 2003 is expected to have a significant number of well line tests and 1 or 2 full-scale flow lines trials in preparation for an expected 3-phase corrosion inhibitor change in 2004 to a more cost effective product.

Section H.1.4 Program Reviews

A number of reviews were conducted throughout the year on specific elements of the corrosion and inspection programs. Specific reviews conducted were,

- **GPB Partner Reviews** – Regular reviews of the corrosion management program at GPB were conducted with corrosion and integrity experts for the major GPB partners.
- **DOT Presentation** – Presented the GPB corrosion management programs described in the 2001 charter report to the Western Regional Chief of the DOT and a number of his staff.
- **ADEC Review** – ADEC and third party consultant review and comments on the BP Corrosion Monitoring Charter Agreement Reports.

The mixture of topics and the number of reviews in 2003 will differ from those completed in 2002 and reflects the change in emphasis in the program through time and the impact of other external factors.

Section H.1.5 2002 Corrective Actions

This section summarizes the corrective actions taken as a result of corrosion monitoring and inspection results exceeding the specified targets. These targets are detailed in Section B Table B.11.

Table H.2 notes the corrective mitigation actions taken as a result of ER probe readings exceeding target.

Equipment ID	Cause	Action
A Pad	Increased Corrosivity	Increased CI by 5%
A Pad	Increased Corrosivity	Increased CI by 5%
DS04	Increased Corrosivity	Increased CI by 5%
GHX-E	Increased Corrosivity	See Table H.4
A Pad	Increased Corrosivity	Increased CI by 5%
CL05B	Increased Corrosivity	Increased from 3 to 4 gpd.

Table H.2 Correction Mitigation Actions from ER Probe Data

Table H.3 notes the corrective mitigation actions taken as a result of weight loss coupons exceeding target.

Equipment ID	Cause	Action
DS14	Increased Corrosivity	Increaded CI by 10%
CL14D	Increased Corrosivity	Increased CI by 10%
CL05D	Increased Corrosivity	Increased CI by 20%
F Pad	Increased Corrosivity	See Table H.4
Seawater	O_2/Microbiological	Multiple

Table H.3 Correction Mitigation Actions from Coupon Data

Table H.4 notes the corrective mitigation actions taken as a result of inspection information.

Equipment ID	Cause	Action
DS09	Increased Corrosivity	Increaded CI by 10%
H Pad	Increased Corrosivity	Increased CI by 10%
F Pad	Increased Corrosivity	Increased CI by 10%
GHX-E	Increased Corrosivity	Increased CI by 25%
PW system	Increased Corrosivity	Multiple
SW system	O_2/Microbiological	Multiple

Table H.4 Correction Mitigation Actions from Inspection Data

Section H.2 2003 Corrosion and Inspection Goals

The 2003 corrosion and inspection goals will be focused on optimization and continuous improvement of the programs. In general, there are not expected to be any significant changes from the overall scope and scale of the 2002 effort.

Section H.2.1 Corrosion Monitoring

There are no plans to significantly change the corrosion weight loss coupon-monitoring program in 2003. The emphasis in the produced water and 3-phase production system will be on maintaining the current level of performance, and in the seawater system reversing the negative trends seen in the last 24 months.

Section H.2.2 Inspection Programs

The internal inspection program is planned to be largely unchanged in 2003 from 2002. The expected activity level again will be about 60,000 in total for GPB spread between both the field and facilities.

The major change in the inspection program for 2002 was the implementation of a much larger external corrosion inspection program. The current planned activity level for 2003 is similar to that for 2002 at about 35,000.

2003 will see the completion of the 5-year program to conduct a baseline inspection on all the cased piping segments. As with prior years, the program is expected to be on-track for completion with a scope typical of prior years at ~280 segments.

Section H.2.3 Chemical Optimization

Chemical dosage optimization will continue in 2003 with a particular focus on optimization of rates by minimizing the variability in the dosage rates. This will primarily be achieved through the improved level of access to the corrosion inhibitor injection rate data provided by the fully electronic recording system implemented in late 2002.

There are currently no plans to replace the current 3-phase continuous corrosion inhibitor at GPB in 2003. The next generation of corrosion inhibitor is expected to be introduced to the field in 2004. Therefore the main focus for 2003 will be the testing and verification, via well line and flow line trials, of the candidate replacement products.

For the seawater system, there will be a continued focus on the chemical mitigation programs, oxygen scavenger injection and biocide treatments, which were augmented in 2002 and are intended to reverse the negative corrosion rate trends in the last 2 years.

Section H.2.4 Program Improvements

As discussed in the report, the main focus for improvement is the seawater injection system. Although a number of improvements were made throughout 2002, the operational upsets at the plant have made it difficult to assess the impact of these improvements.

For the seawater system, a number of corrective actions were instigated in the latter half of 2001 and 2002. The focus for 2003 will be to ensure that these corrective actions deliver the performance improvement anticipated. Clearly, if there is no improvement in performance, additional corrective actions will be required.

In addition to the obvious area of improvement in the seawater system, the intention is to be able to retain and continue the current levels of control in the other major systems such as 3-phase and produced water injection. Since the performance of these systems is often closely and subtly linked, 'maintenance' of corrosion control continues to represent a highly complex and resource intensive activity.

Part 2

Alaska Consolidated Team Business Unit

Section B-H

Section B ACT – Corrosion Monitoring Activities

ACT presently consists of four producing areas: Endicott, Milne Point Unit (MPU), Northstar and Badami. Northstar was added to ACT as it came on production in the second half of 2001.

Each of the producing field within ACT has its own unique set of circumstances and challenges.

Milne Point Located approximately 25 miles west of Prudhoe Bay, the field began production in 1985. On January 1st, 1994, BP acquired a majority working interest from the prior owners, and assumed operatorship. Since 1994 production and proven reserves have been increased and Milne Point production now averages approximately 45,000 bpd.

Endicott Located north of Prudhoe Bay, Endicott consists of two islands, the main Production Island (MPI), and the satellite-drilling island (SDI) at the end of a causeway. Endicott 3-phase production piping is made largely of duplex stainless steel, which significantly reduces the environmental risks.

Badami Remotely located east of Prudhoe Bay, Badami has a relatively low production volume due to challenging reservoir conditions. The Badami production facilities, like other recent developments on the North Slope, are constructed using a much smaller surface footprint than GPB and do not have permanent road access, therefore having a much reduced impact on the environment.

Northstar Located offshore, is the first offshore oil field in the Beaufort Sea not connected to land by a causeway. As with Badami and other recent developments, Northstar drilling and production operations are built on smaller footprint than the original North Slope facilities. Northstar produces a light, 42 degrees API gravity, high quality sweet crude, that is transported to shore in a pipeline that is three times thicker than required for pressure containment.

In addition to the unique challenges associated with location and history, each of the ACT producing field has its own unique corrosion environment. Table B.1 illustrates, on a relative basis, the corrosivity of each producing field within ACT along with the materials of construction and corrosion mitigation. GPB is included in the table for comparative purposes. Listed in the table are, for each field, the typical water cut in percent, average wellhead temperature, and the percent CO_2 in the produced gas. Also listed, for each field are the generally used materials of construction for both the production system and the water injection system.

	Prod Fluid Characteristics				Material of Construction[a]			
					Production		Injection	
Field	H_2O, %	T °F	P_{CO_2} %	CR[b]	WL	FL	WL	FL
GPB	70	150	12	H	CS+CI	CS+CI[c]	CS+CI	CS+CI
END	90	150	18	H	DSS	DSS	CS+CI	CS+CI
MPU	47	125	1.5	L/M	CS	CS[d]	CS+CI	CS+CI
Northstar	0.8	160	5	M	CS+CI	N/A	N/A	N/A
Badami	0.3	65	0	L	CS	N/A	N/A	N/A

Notes

(a) CS is carbon steel, CI is corrosion inhibitor, DSS is duplex stainless steel
(b) Unmitigated relative corrosion rate, H – high, M – medium, and L - low
(c) There are a limited number of Duplex Stainless Steel flow lines in GPB
(d) Two production flow lines are inhibited at MPU

Table B.1 Relative Corrosivity of BP North Slope Production

The table shows that in general the production fluid characteristics for the ACT producing field are general less susceptible to corrosion compared with those at GPB with the exception of Endicott. However, for Endicott, this corrosion risk is mitigated in the production system through the use of duplex stainless steel as the material of construction for the production flow lines.

In addition, with the exception of Endicott, to the generally lower risk of corrosion, the ACT fields are of a smaller scale when compared to GPB. For example, as can be seen in Table B.1, neither Northstar nor Badami have any significant non-common carrier cross-country flow lines. An illustrative assessment of the relative size of the ACT producing field and GPB is provided in Table B.2.

In general, Table B.2 shows that the ACT fields combined are of a much smaller scale than GPB. Also, it should be noted, that when comparing GPB and ACT facilities that these facilities differ enormously in age from over 25 years since first oil for GPB to ~12 months for Northstar.

Metric	ACT	GPB	$\frac{ACT}{(ACT+GPB)}\%$
Production Trains	4	21	16%
Prod and Inj Wells	230	1475	13%
Non-common carrier FL	105	1350	7%
Acreage	75000	203000	27%

Table B.2 Illustrative Comparison of Scale Between ACT and GPB

Section B.1 Endicott

Endicott is a mature waterflood field. The fluid properties (high temperatures, high CO_2 content) indicate the corrosivity of the produced water to be high. Due to this high corrosivity, much of the field production system was fabricated from duplex stainless steel, a corrosion resistant alloy and therefore, corrosion is not a significant concern for much of the production system. In the Endicott production system, the only carbon steel is the C-Spool, connecting the wellhead to the duplex stainless steel well line. These C-Spools are inspected regularly and replaced when no longer fit for service as per the criteria discussed in GPB Section E.

Service	Miles	Int. Insp.	Ext. Insp.[1]
Oil x-country lines	3.5	4 (in vault)	4 (in vault)
Oil - Well Pads	2.5	1327	0
Water x-country lines	3.5	104	4 (in vault)
Water - Well Pads	1.7	200	9 (in vault)
Gas x-country (GLT/MI)	7	15	4 (in vault)
Gas - Well Pads	1.2	26	9 (in Vault
Fuel Line - Gasoline	N/A	5 foot excavation	5 foot excavation
Fuel line - diesel	N/A	5 foot excavation	5 foot excavation

[1] The external corrosion program concentrated significantly on the Oil Sales line in 2002.

Table B.3 Endicott Summary of Lines and NDE Inspections 2002

The primary corrosion concerns are in the water injection system, mainly the Inter-Island Water Line (IIWL) carrying injection water to the satellite production island (SDI) from the main production island (MPI). Corrosion control of the water injection system relies on corrosion inhibition of the injection water, supplemented by a biocide and maintenance pigging program. The primary monitoring method for the IIWL is ultrasonic inspection of 25 locations. Table B.3 summarizes the inspection program for Endicott for 2002.

Section B.2 Milne Point

Fluid properties (low temperatures, low CO_2 content) indicate the corrosivity of the production fluids at MPU to be low. The primary corrosion concerns are in the water injection system and external corrosion of buried piping. Solids contribute to the corrosion mechanism of the production system as evidenced by under-deposit corrosion found in the production system in 2001. Corrosion inhibition, supplemented by a biocide and maintenance pigging program began in mid-2000 in the water injection system. As a result, corrosion rates, as exhibited by weight loss coupons, have dropped significantly over the past two years. Corrosion inhibition of the K-pad production flow line was initiated in 2001. Additionally, corrosion inhibition of the newly developed S-Pad began late 2002. Table B.4 summarizes the inspection program for Milne Point for 2002.

Service	Miles	Int. Insp.	Ext. Insp.[2]
Oil x-country lines	24	80	0
Oil – Well Pads	N/A[1]	754	47
Water x-country	15	35	0
Water – Well Pads	N/A[1]	449	23
Gas x-country	14	0	0
Gas – Well Pads	N/A[1]	283	0

[1] Totals not available
[2] The external corrosion program concentrated significantly on the Oil Sales line, and outside facility piping in 2002.

Table B.4 Milne Point Unit Summary of Lines and NDE Inspections 2002

Section B.3 Northstar

Northstar began production in November 2001. Corrosivity is expected to be low to moderate initially, but will tend to increase over time with the injection of Prudhoe Bay Unit gas into the reservoir, which has a higher CO_2 content than the natural Northstar reservoir. Table B.5 summarizes the inspection program for

Northstar in 2002. Data is limited as the production facility is relatively new. Note that the line lengths for Northstar are in feet as the production facility is contained in a comparatively small footprint.

Service	Feet	Int. Insp.	Ext. Insp.
Oil Pipe rack	1200	0	0
Oil – Well Pad	280	106	0
Water Pipe rack[1]	2400	0	0
Water – Well Pad[1]	70	17	0
Gas Pipe rack	600	0	0
Gas – Well Pad	140	26	0

Disposal system; Northstar does not have an active water injection system.

Table B.5 Northstar Summary of Lines and NDE Inspections 2002

Section B.4 Badami

Badami is currently considered a low risk from a corrosivity standpoint, as there is little water production and low CO_2 content. Table B.6 summarizes the inspection program for Badami.

Service	Feet	Int. Insp.	Ext. Insp.
Oil –Well Pad	840'WL , 320' HDR	9	0
Gas	240'WL, 320'HDR	0	0
Disposal Well	400'	0	0

Note Badami does not have an active water injection system.

Table B.6 Badami Summary of Lines and NDE Inspections 2002

Section B.5 Overall Inspection Activity Level

Table B.7 summarizes the overall inspection activity since 2000, as can be seen from the table the overall activity level has remained approximately constant at between ~3400 items per year.

	Surface	2000	2001	2002
Endicott	Int	1346	1480	1676
	Ext	16	16	30
	Total	**1362**	**1496**	**1706**
Milne Point	Int	1419	629	1601
	Ext	378	1577	70
	Total	**1797**	**2206**	**1671**
Northstar	Int	-	16	149
	Ext	-	0	0
	Total	**-**	**16**	**149**
Badami	Int	0	9	9
	Ext	0	0	0
	Total	**0**	**9**	**9**
Grand	**Total**	**3159**	**3727**	**3526**

Table B.7 Overall Inspection Activity Summary 2000 - 2002

Section C ACT - Coupon Corrosion Rates

Corrosion probes are not extensively used in ACT fields. The following data therefore relate to corrosion coupons only.

Section C.1 Endicott

Table C.1 depicts the metrics for corrosion monitoring at Endicott for 2002. Historical data are shown in Figure C.2.

As shown in Figure C.2, the corrosion trend for the production system has remained above 2 mpy; however as noted previously, the major portion of the system is fabricated from duplex stainless steel and the data are used primarily for monitoring produced fluid corrosivity and erosion tendency. The lower, relatively constant corrosion rates in the water system reflect the effectiveness of the corrosion mitigation program.

System	Access Fittings	% WLC < 2 mpy
Water Injection - Pads	15	100%
Water Injection – x-country	1	100%
Oil Production – Pads	72	68%

Table C.1 Endicott Corrosion Coupon Monitoring 2002

Section C.2 Milne Point

Table C.3 depicts the metrics for corrosion monitoring at Milne Point for 2002. Historical data are shown in Figure C.4.

Figure C.4 illustrates the low corrosion rates for the MPU production and source water systems. Of concern historically were the relatively higher corrosion rates in the water injection system. These higher corrosion rates led to the initiation of corrosion inhibition in the water injection system in mid-2000. The initial indications are that the inhibition is having a positive effect on the corrosion rate as the weight loss coupon corrosion rates have consistently averaged less than 2 mpy since the inhibition program was implemented.

System	Access Fittings	% WLC < 2 mpy
Production System	27	100%
Water Injection System	7	95%
Source Water Coupons	5	100%

Table C.3 MPU Corrosion Coupon Monitoring 2002

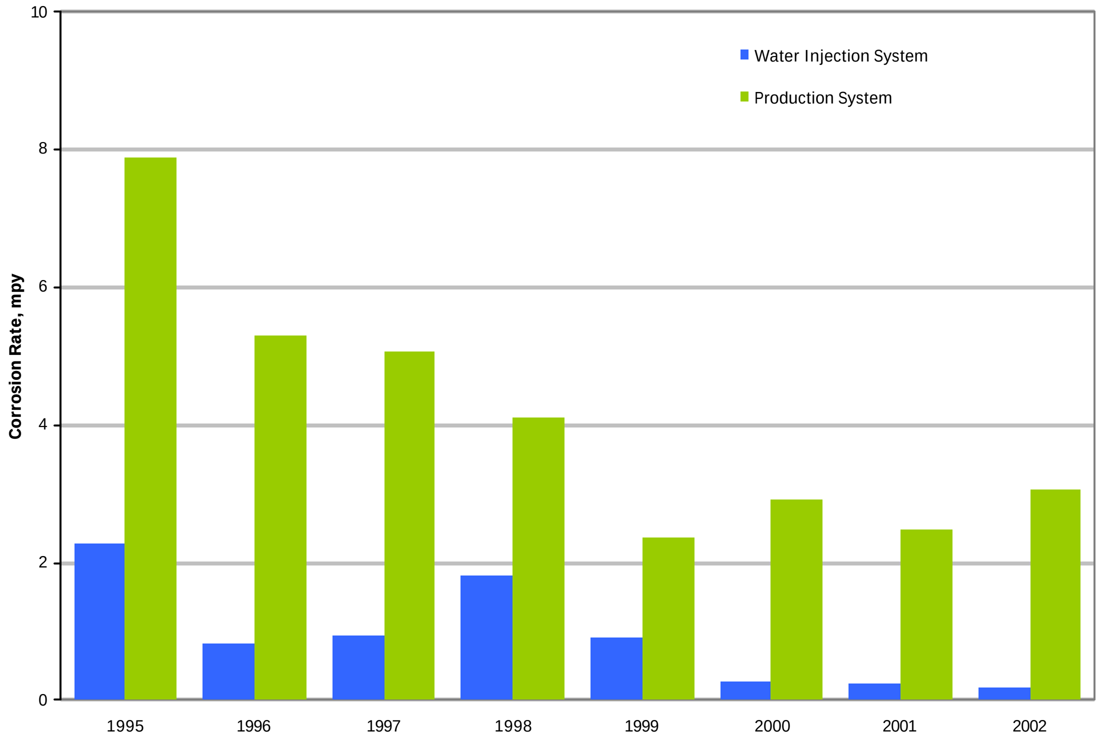


Figure C.2 Corrosion coupon data from Endicott 1995-2002

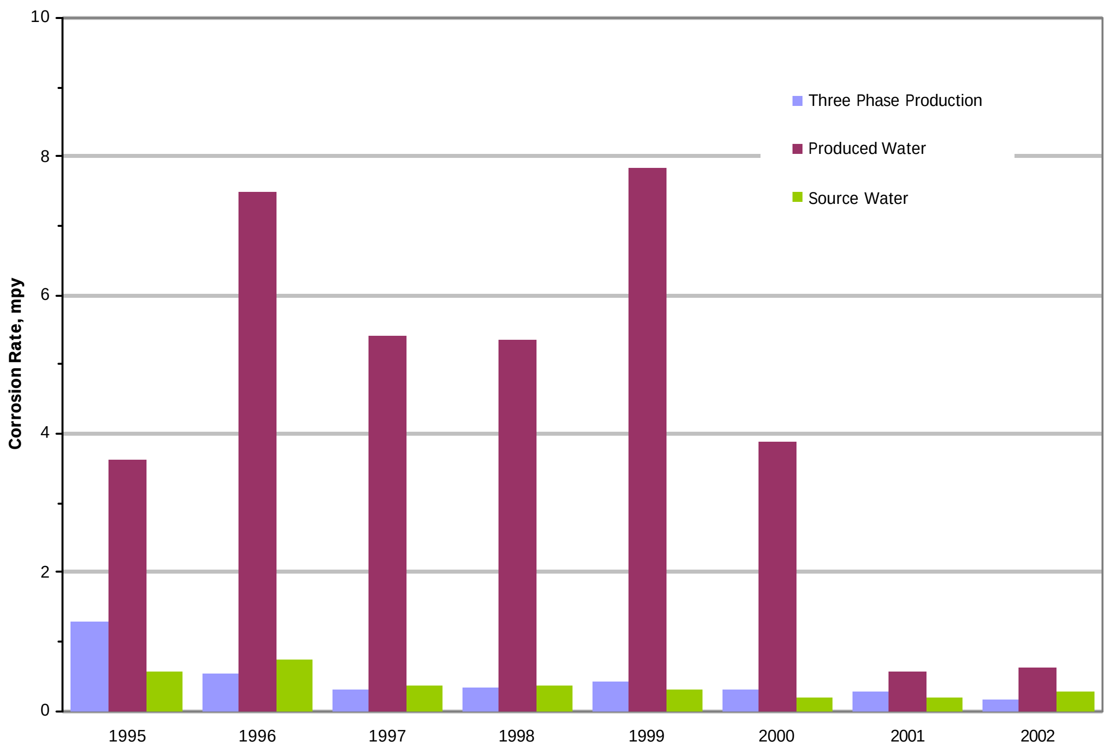


Figure C.4 Corrosion coupon data from MPU 1995-2002

Section C.3 Northstar

The Northstar facility is equipped with corrosion monitoring locations. However, no data is currently available, as coupons have been pulled but not analyzed yet. This data will be reported in the future as it becomes available.

Section C.4 Badami

Badami currently has no corrosion-monitoring program.

Section D ACT - Corrosion Mitigation Activities

Section D.1 Endicott

Corrosion mitigation at Endicott has concentrated on a three-pronged approach of maintenance pigging for line cleanliness, bphysiciding to control bacterial activity and continuous injection of a corrosion inhibitor for corrosion control. As noted earlier, the primary monitoring tool for effectiveness is the quarterly UT inspection of 25 locations along the IIWL. These inspections indicate there is currently slight corrosion activity in the IIWL, but down significantly from the 1995-1997 timeframe. A historical perspective of the reduction in corrosion activity since this three-pronged approach was implemented is shown in Figure D.1. The number of locations showing corrosion increases has been fairly constant over the past three years, indicating slight corrosion activity. The maintenance pigging program was suspended for approximately two months in 2002 for repairs to the launcher. Also, a slight inhibitor modification was made in 2002, however the inhibitor formulation is virtually unchanged from the previous version. Treatment volumes vary dependant upon operational swings in injection rates and reservoir optimization efforts. The current treatment concentration is 17 ppm. Optimization efforts prior to 2003 had concentrated on the biocide program. The line is currently under review to modify the corrosion inhibitor treatment type and/or rate.

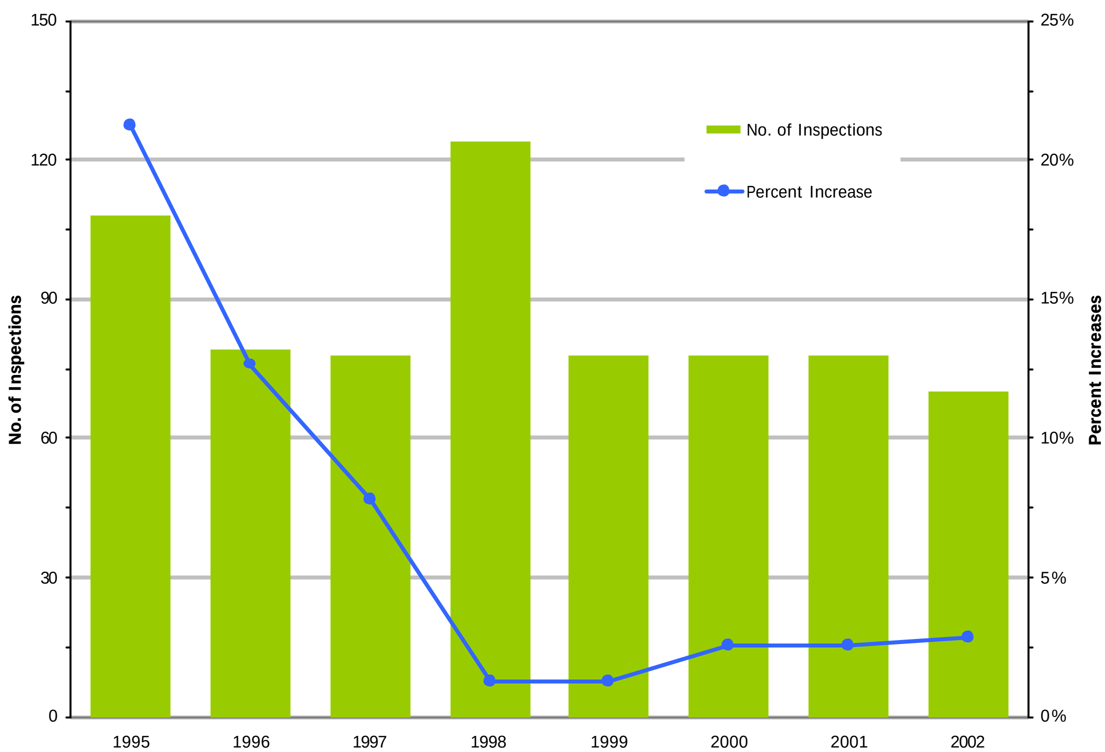


Figure D.1 Endicott IIWL Quarterly UT Readings Through 2002

In the production system, the primary damage mechanism is erosion. The erosion rate, in this mainly duplex stainless steel system, is mitigated through inspection and velocity management. Wells are risk ranked by mixture velocity approximately once per month. This information is used to determine inspection frequency, and is also used by the operating personnel to determine if production rate, and hence fluid velocity, for the well should be reduced. Figure D.2 is an overview of the velocity data for Endicott for 2001 and 2002. Shown are the numbers of wells within L/R ratio ranges, where L is the mixture velocity and R is the allowable erosion velocity as defined by API RP 14E.

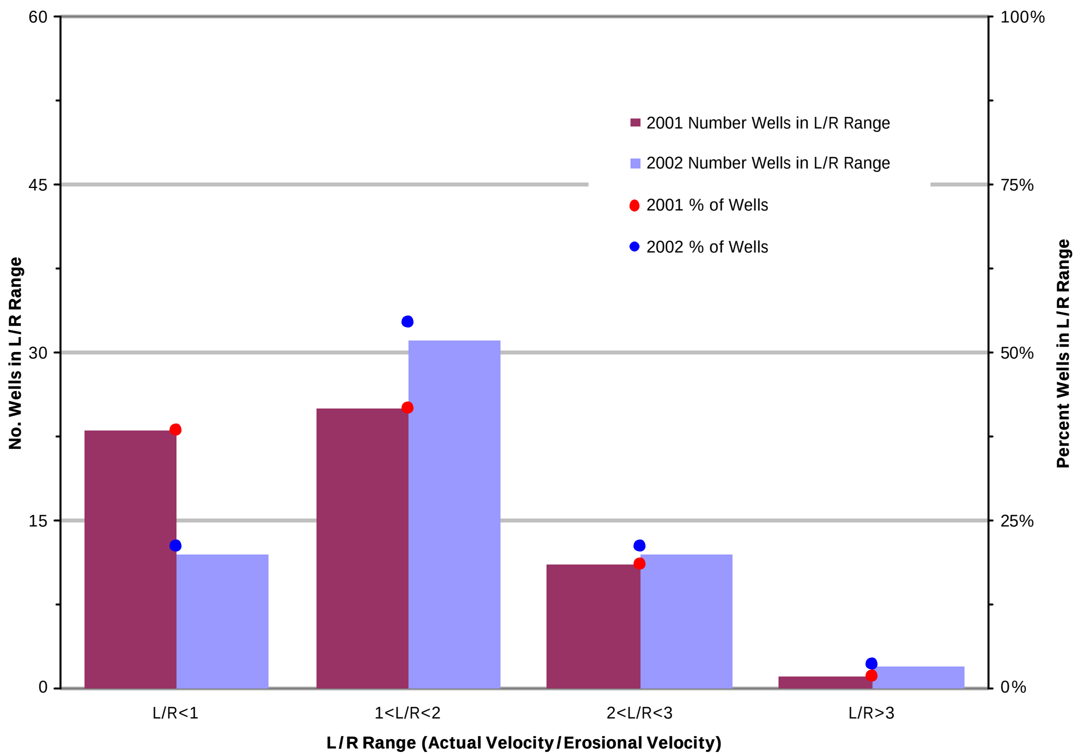


Figure D.2 Endicott Velocity Monitoring 2001-2002

API RP 14E defines an allowable velocity for the avoidance of erosion, based on the fluid properties (namely density) and material of construction. API RP 14E is based on experience with steam service and is known to be conservative when applied to oil production systems, particularly where corrosion and erosion resistant materials are used. Actual velocities are expressed as a ratio of the allowable velocity as defined by API RP 14E, with the aim being to limit velocities to less than 3 times the allowable velocity. This factor of 3 reflects BP's North Slope experience that production fluids with minimal amounts of entrained solids may exceed the API RP 14E erosion velocity through stainless steel pipelines by this amount with minimal risk of erosion. Equipment exhibiting high velocities is inspected at intervals ranging from weekly to bi-annually dependant upon the L/R Ratio, input from Well Operations, and inspection results. The inspection frequency for the two wells showing an L/R Ratio greater than 3 has been increased from quarterly to monthly.

Section D.2 Milne Point

Corrosion inhibition of the water injection system began in mid-2000, along with a more frequent maintenance pigging program. Weight loss coupon data indicates the system is coming under control as the corrosion rates have averaged less than 2 mpy since mid-2000. This represents a significant reduction from previous years and can be seen in Figure D.3.

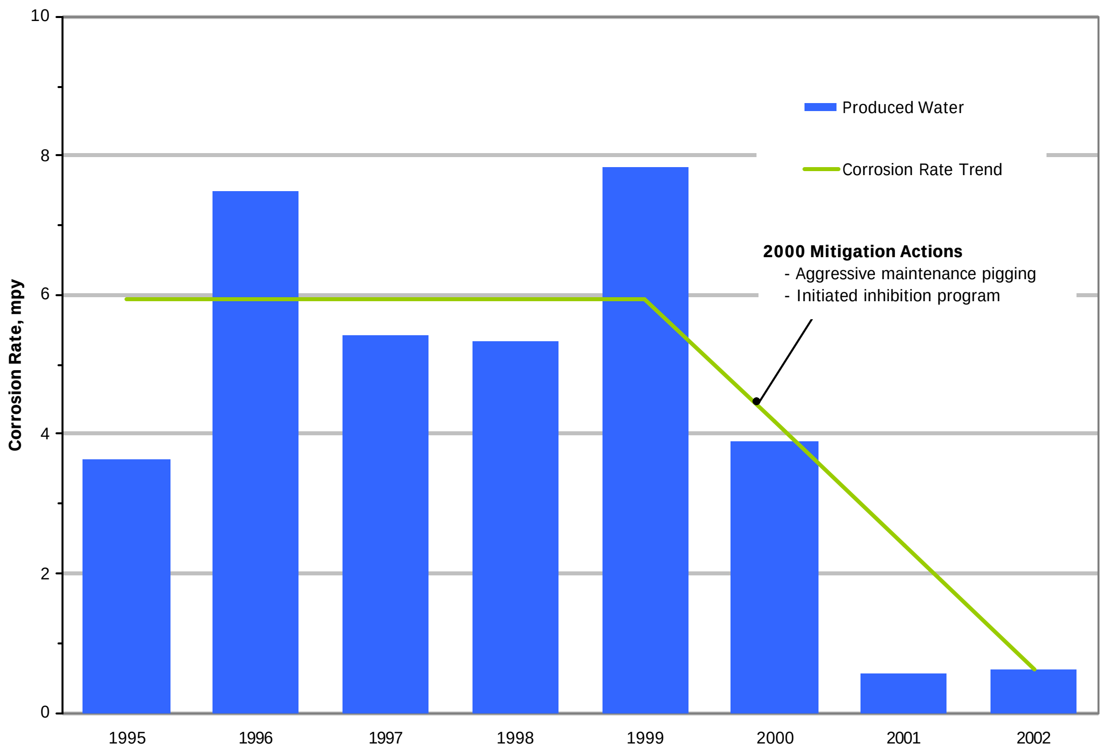


Figure D.3 Milne Point Produced Water Corrosion Rate Trend

The majority of the production lines are not currently inhibited, although the long-term goal is to continuously inject corrosion inhibitor into the three-phase system. Corrosion inhibition on the K-Pad 3-phase production flow line was initiated in 2001 after inspections indicated significant under-deposit corrosion damage. The damage was associated with extremely low flow conditions, allowing solids to accumulate in the line.

Treatment concentration is 100 ppm based on water production. In conjunction with the initiation of inhibitor injection, the K-Pad production line is pigged approximately monthly.

In addition, as a result of finding the corrosion damage in the K-pad line, the line was smart pigged in June 2002 and the results from the smart pig run were added to the routine inspection program.

The newly developed S-Pad was designed for continuous inhibition. Corrosion inhibitor is continuously injected into the power fluid supply for the down hole hydraulic pumps. Since this water is separated and re-circulated as power fluid at the pad, only minor amounts of water are sent through the cross-country flow line to the separation facility. Additional makeup water for use in the power fluid system is treated at a rate of 20 ppm corrosion inhibitor. This program will be optimized based on the results from the inspection and corrosion monitoring programs.

The remaining flow lines are under review for potential corrosion inhibition. Prioritization will be based on flow characteristics and inspection trends.

Inspection increases in the well pad production lines indicates there is slight corrosion activity occurring over the long term. As a result, it is anticipated that the MPU production system will eventually be on continuous corrosion inhibition. This evaluation is ongoing.

As production rates are typically low, the velocities are consequently also lower and erosion is not a significant concern. There is therefore no formal velocity management program.

Section D.3 Northstar

Northstar is inhibited with continuous injection of corrosion inhibitor into the well production lines. Inhibitor concentration is set at 100 ppm based on water, but a minimum amount of 2 gallons/day is injected regardless as the production contains very little water at this time (one percent or less water cut).

Section D.4 Badami

Corrosion inhibition is currently not required at the Badami field based on modeling of the corrosivity of the fluids, the low water-cut, results from the facility and pipeline inspection program.

Section E ACT - Inspection and Corrosion Increases/Rates

Section E.1 External Inspection

Section E.1.1 Endicott

Underground/cased lines at Endicott are inspected per the frequency listed in Table E.1. Of the lines inspected in 2001, no significant corrosion was noted.

Line	Crossings	Year Surveyed	Method	Max Inspection Interval
WTR - Inter-Island	1	2001	EMI	10 Years
GAS - Inter-Island	1	2001	EMI	10 Years
OIL	1	N/A		N/A Duplex Stainless Steel
MI Line	1[1]	N/A		
WTR – WL	2	1 line in 2000	EMI	10 Years for Carbon Steel Other line is Duplex Stainless Steel
GAS - WL	1	2000	EMI	10 Years

1 New in 1998, inspection ports for sniffing, permanently sealed, can be inspected by excavation only

Table E.1 Cased Piping Inspections

In addition, the vaults where the Inter-Island Water and Gas Lines pass are visually inspected annually. Minor external corrosion has been found, but it has not increased. The aboveground MI line and Gas Line are to be inspected with TRT in 2003.

Section E.1.2 Milne Point

Table E.2 summarizes the external inspection program at MPU since 1997. In 2002, five excavations were performed on buried lines at I-Pad for external corrosion inspection. This is the 70 items accounted for in Table E.2 for 2002. Five locations were repeat locations with one of these repeat locations showing a slight increase in corrosion. An additional seven locations showed minor external corrosion, less than 20% wall loss. The corroded areas were mitigated.

Year	Total Insp	Repeat Insp	Increases	% I's
1997	26	0	0	n/a
1998	441	10	0	0.0
1999	101	65	0	0.0
2000	205	104	28	26.9
2001	179	20	5	25
2002	70	5	1	20

Table E.2 MPU Inspection Summary- External

Table E.2 does not reflect the total number of TRT inspections performed in 2001. A total 2100 items were inspected with TRT in 2001, however the majority of these were associated with outdoor facility piping.

Section E.1.3 Badami

External inspections that have been done to date at Badami are associated with the internal inspection program where insulation was removed for ultrasonic inspection of well line elbows. No evidence of corrosion was noted.

Section E.2 Internal Corrosion Inspection

Section E.2.1 Endicott

Figures E.3 and E.4 indicate the percentage of inspection increases since 1995 for the well lines and flow lines at Endicott. There were no increases in the 3-phase production cross-country line as it is manufactured from duplex stainless steel, a corrosion resistant alloy. Minor activity has been noted in the water injection system flow line, the Inter-Island Water Line (IIWL).

Figure E.3 shows corrosion activity in the well lines by inspection for both the production and water injection systems at Endicott. These trends have remained relatively constant since 1998. The production system inspection data is used to alert Operations of potential replacements of the carbon steel C-Spools at the wellheads. The inspection increases in the water injection system well lines have been relatively constant since 1996 reflecting the improvements in the chemical mitigation program undertaken at Endicott. The increases in the PW/SW well lines in 2002 are under review as noted in ACT Section B, for potential inhibitor change and/or concentration increase.

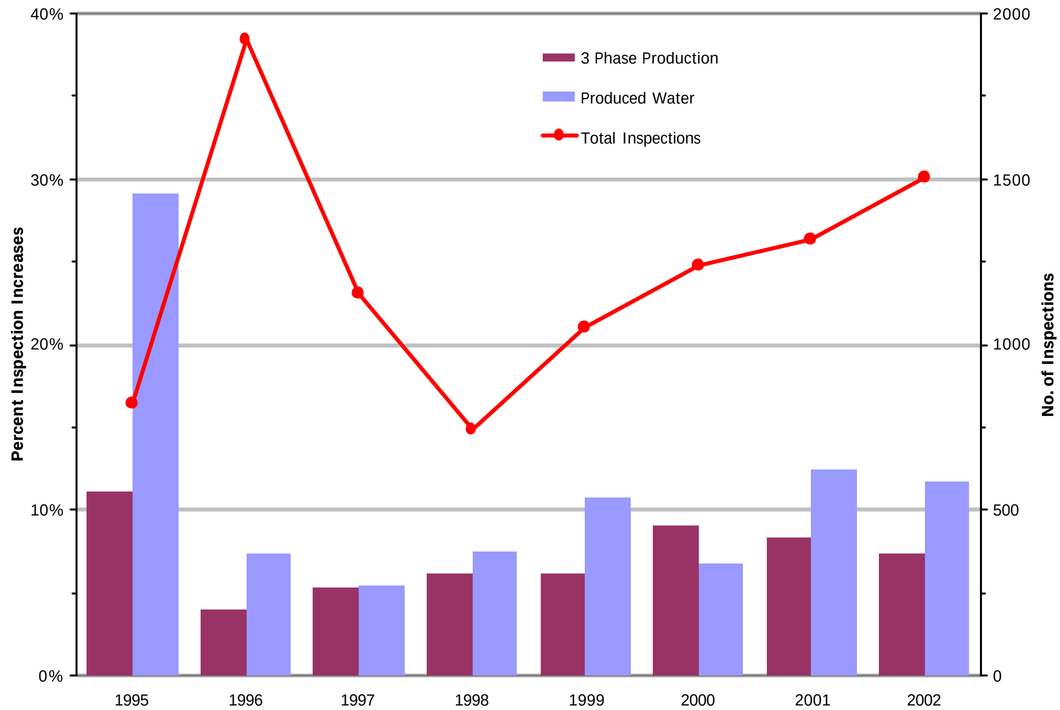
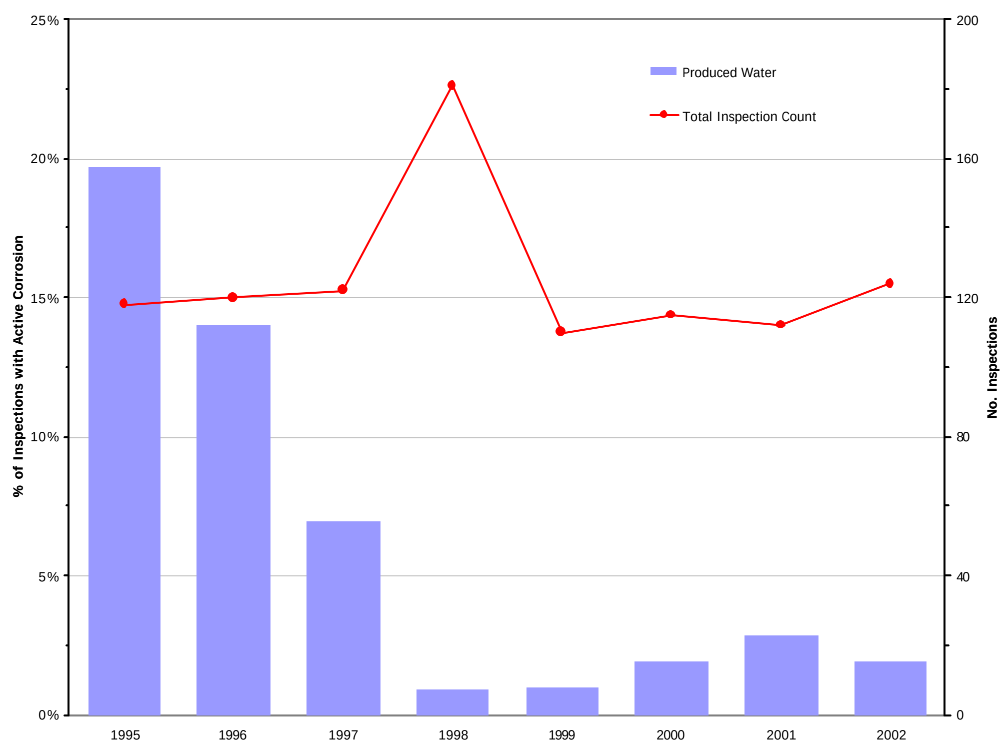


Figure E.3 Detection of internal corrosion of well lines by inspection at Endicott 2002



Note: Historically, there are no inspection increases in the production line or the gas line since 1995

Figure E.4 Detection of internal corrosion of flow line by inspection at Endicott 2002

Figure E.4 shows a trend of declining inspection increases since 1995 for the IIWL at Endicott. This trend is indicative of the improvements made to the water injection mitigation program. There has been, however a slight increase in activity in the inter-island water line over the past two years. As discussed above, the treatment regime for the PW/SW system is under review for potential inhibitor changes. In addition, the pigging program was suspended for approximately two months in 2002 while awaiting repairs to the pig launcher.

It should be noted that the corrosion increases in the three-phase production are in carbon steel C-Spools that are managed through planned replacement at the FFS criteria discussed in GPB Section E.

Section E.2.2 Milne Point

BP became operator at Milne Point in 1994, and from this date to 2000 the inspection program has been aimed at establishing the baseline condition in the MPU systems. It is only with the 2000 data and beyond that trending of inspection increases has been possible with inspection locations being repeated. The results of this comparative data can be seen in Figure E.5. The figure shows that the total number of inspection items has consistently increased since 1998. Locations showing increased corrosion activity has reduced for both the 3-phase production and the produced water lines from 2001 to 2002. All increases in the production flow lines are attributable to the corrosion in the K-pad flow line as discussed previously.

With the corrosion identified in the K-pad line, additional inspections using real time radiography were performed on several other lines. These inspections included 1400 feet (approximately 15%) of the next lowest velocity line in the field, B-pad production line, with no additional corrosion noted, and 400 feet (approximately 18%) of the E-pad production line, also with no additional corrosion noted. The E-pad line takes production from the K-pad line.

Approximately 400 feet of real time radiography was also performed on the F-pad 3-phase production flow line, as a follow-up verification to the smart pig run in 2001. The smart pig reported significant damage along the first 1000 feet of line length. Upon verification, only one minor internal pit was detected, indicating the smart pig erroneously over-estimated the depth and extent of corrosion damage.

The locations showing increased corrosion activity in the produced water flow lines are over an extended timeframe that included the period of corrosion activity prior to the establishment of the corrosion inhibition and maintenance pigging programs begun in 2000.

Figure E.6 shows the historical detection of internal corrosion of well lines by inspection at MPU through 2002. This again shows the progress made in obtaining increasing total and repeatable inspection data. In the Produced Water data, numerous repeat inspections were done from the period of 2000 or earlier, indicating that corrosion inhibition had not been fully established as it only began in 2000. For example, of the increases shown for the Produced Water System in 2002 in Figure E.6, fully 64% of these increases were from a period of the previous inspection being in 1999 or earlier.

Section E.2.3 Badami

As Badami only came on stream in 1998, there is little historical data for this field. A 2002 follow-up to the baseline survey performed in 2000 indicates no corrosion, erosion or mechanical damage on the oil production well lines.

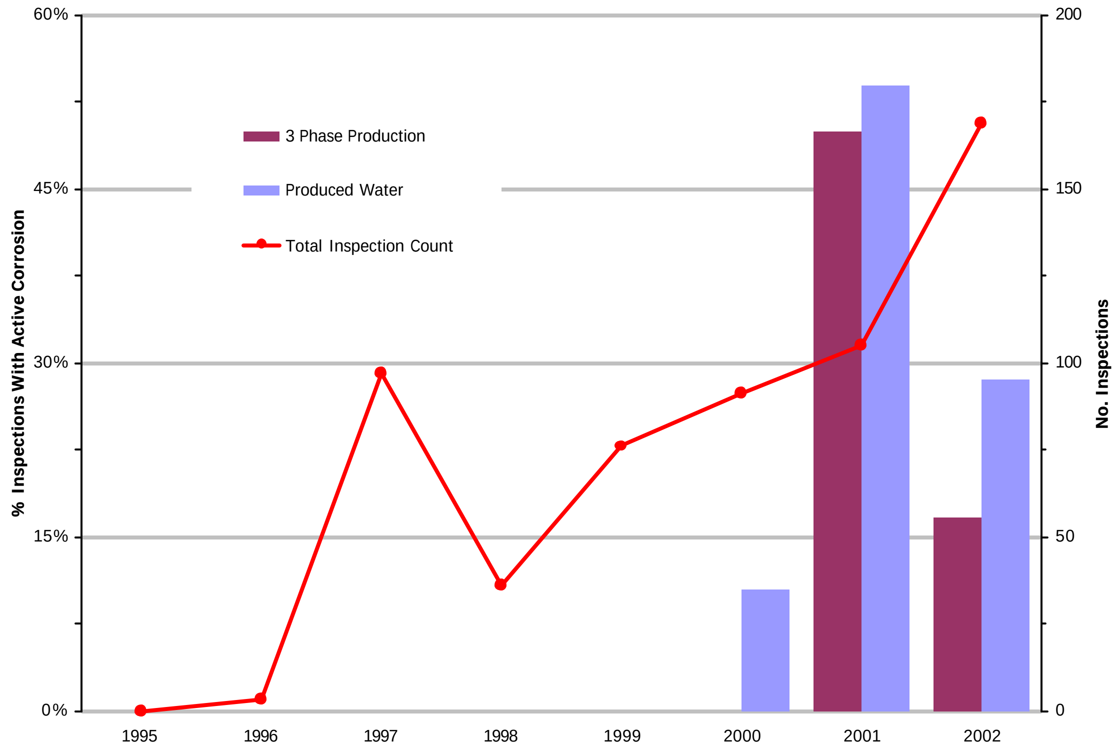


Figure E.5 Detection of internal corrosion of flow lines by inspection at MPU 2002

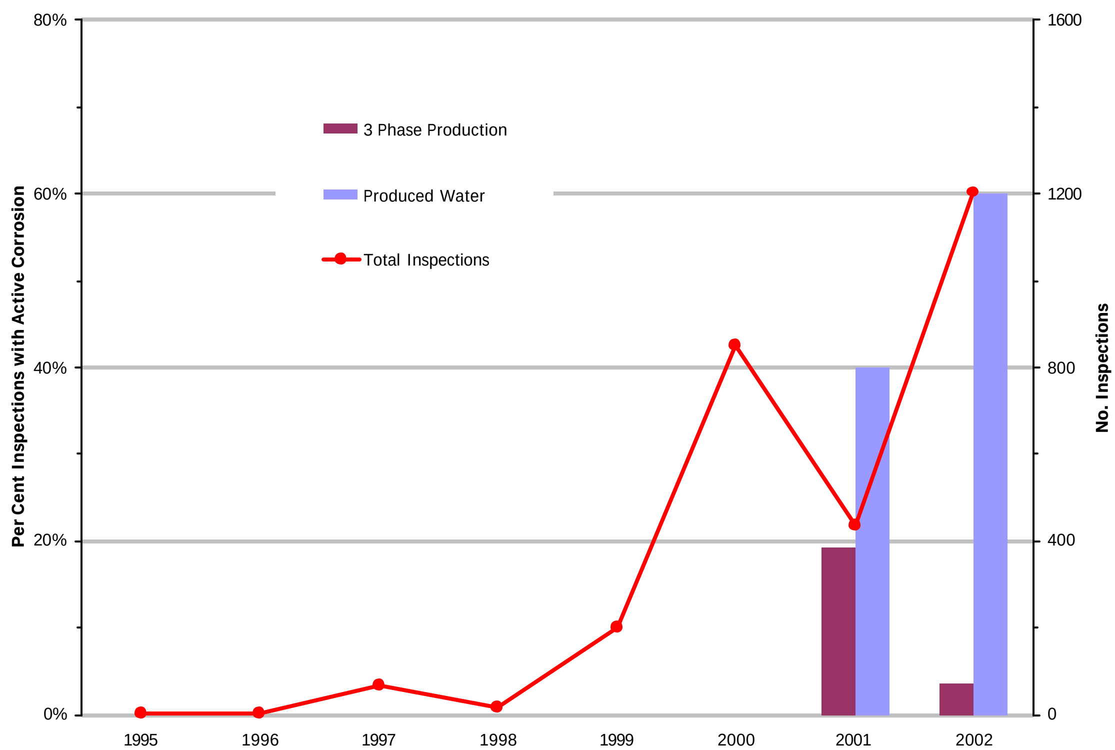


Figure E.6 Detection of internal corrosion of well lines by inspection at MPU 2002

Section F Act – Repair Activities

Table F.1 summarizes the repair activity for ACT. There were 13 repairs identified for ACT of which 8 were at Endicott and 5 at Milne Point.

Service	Type	Int	Ext	Mechanical
Oil	FL	4	1	-
	WL	6	-	1
PW	FL	-	-	-
	WL	1	-	-
	Total	**11**	**1**	**1**

Table F.1 ACT Repair Activity

Four of the Endicott repairs were to well line C-spool sections due to corrosion of the weld heat-affected zone (HAZ). Two well line production risers were replaced due to internal corrosion of which one was as a result of a pinhole leak. One duplex pipe spool was replaced due to erosion damage. The one produced water pipe spool was identified for replacement after corrosion damage to two elbows was found.

The five Milne Point repairs were all on the K-pad production flow line of which one was due to external corrosion.

Section G ACT - Corrosion and Structural Related Spills and Incidents

As noted in the previous section, there was only one pin hole leak in 2002 due to corrosion. There were no leaks attributable to structural deficiencies.

Tables G.1, G.2, G.3 and G.4 summarize leak/save and mechanical repair data for Endicott, MPU, Northstar and Badami, respectively.

Service	Leaks	Saves	Sleeves	Comments
Oil x-country lines	0	0	0	
Oil Well Pads	0	6	0	Well 2-30 erosion
Water x-country lines	0	1	0	
Water Well Pads	1	0	0	Well 1-31 pin hole
Gas x-country GLT/MI	0	0	0	
Gas Well Pads	0	0	0	

Note: Leak / Save and mechanical repair data is for year 2002 only.

Table G.1 Endicott Leak/Save and Mechanical Repair Data

Service	Leaks	Saves	Sleeves	Comments
Oil x-country	0	5	5	K-pad flow line
Oil Well Pads	0	0	0	
Water x-country	0	0	0	
Water Well Pads	0	0	0	
Gas x-country	0	0	0	
Gas Well Pads	0	0	0	

Note: Leak / Save and mechanical repair data is for year 2001 only.

Table G.2 Milne Point Leak/Save & Mechanical Repair data

Service	Leaks	Saves	Sleeves	Comments
Oil – Well Pad	0	0	0	
Gas – Well Pad	0	0	0	
Disposal Well	0	0	0	

Note: Leak / Save and mechanical repair data is for year 2001 only.

Table G.3 Northstar Leak/Save and Mechanical Repair Data

Service	Leaks	Saves	Sleeves	Comments
Oil – Well Pad	0	0	0	
Gas – Well Pad	0	0	0	
Disposal Well	0	0	0	

Table G.4 Badami Leak/Save and Mechanical Repair Data

The repair table shows that, to date, the relatively low corrosivity assessment from the beginning of the section is reflected in the level of repair activity.

Section H 2003 Corrosion Monitoring and Inspection Goals

Section H.1 Endicott

The increases in the Inter-Island Water Line (IIWL) and well line inspection data for PW/SW service are the result of minor corrosion activity in a line with extensive pre-existing corrosion. An inhibitor increase is in progress, the effectiveness of which will be monitored through 2003.

No significant changes to the corrosion-monitoring plan are anticipated.

Section H.2 Milne Point

The 2003 plan will continue to focus on the gains made in the past, in particular, continuing to build a more comprehensive baseline inspection for MPU and build the repeat inspection location to establish corrosion inhibition and chemical treatment performance trends.

Analysis of additional production flow lines requiring corrosion inhibition was initiated in 2002 along with the inhibition of the newly commissioned S-Pad flow line. A major goal for 2003 will be demonstrating the efficacy and optimizing these treatment levels.

The Milne Point corrosion evaluation of buried pipe will trial an alternative detection technology that includes fixed monitoring locations of the buried pipe segments. One of the goals for 2003 will be to install these permanent monitoring locations and gain a baseline data set.

Section H.3 Northstar

Corrosion monitoring and inspection data will be reviewed as it becomes available. Changes to the inspection and mitigation activity will be dictated by this data in conjunction with process data. This is an ongoing activity that will continue for a number of years as the corrosion management programs are established at the new production facility.

Section H.4 Badami

As the Badami fluids are shown to be of relatively low corrosivity, no major changes are anticipated. The plan is to monitor corrosion activity with the annual integrity surveys as has been done in the past.

Appendix 1

Glossary of Terms

Glossary of Terms

Term	Definition/Explanation
3 phase production	Unprocessed well head fluids, oil, water, gas – same as OIL
ACT	Alaska Consolidated Team
ATRT	Automated tangential radiographic testing
BAD	Badami
BP/BPX(A)	BP Exploration (Alaska) Inc.
CCL	Cross country line
CI	Corrosion inhibitor
CIC	Corrosion, Inspection and Chemicals
CIP	Comprehensive Inspection Program
CL	Common line – same as LDF
CMS	Corrosion management system
CPF	Central processing facility
CR	Corrosion rate, mpy
CRA	Corrosion resistant alloy
CRM	Corrosion rate monitoring inspection program
Cross Country lines	Pipelines from the manifold building to major facility
CUI	Corrosion under insulation
CW	Commingled Water
DRT	Digital radiography
END	Endicott
ER	Electrical resistance probe – see corrosion monitoring
ERM	Erosion rate monitoring inspection program
FL	Flow line – same as cross-country
FIP	Frequent inspection program
Frequency C	Continuous
Frequency D	Daily
Frequency H	Hourly
Frequency M	Monthly
Frequency Q	Quarterly
Frequency Y	Yearly/annual
FS	Flow station
G	Gas
GC	Gathering center
GLT	Gas lift transit
GPB	Greater Prudhoe Bay
IIWL	Inter Island Water Line - Endicott
LDF	Large diameter flowline – same as CL
LIS	Lisburne
MFL	Magnetic flux leakage
MI	Miscible injectant
mil	$\frac{1}{1000}$ th of an inch
MIMIR	**M**echanical **I**ntegrity **M**anagement **I**nformation **R**epository BPX(A) corrosion and inspection database
MPI	Main Production Island - Endicott
mpy	Corrosion rate/degradation rate – mils per year
MPU	Milne Point Unit
MW	Mixed water
NDE/NDT	Non-destructive examination/testing
NIA	Niakuk

Glossary of Terms

Term	Definition / Explanation
NGL	Natural gas liquids
NST	Northstar
OIL	OIL service is three phase production service
OWG	Oil, water and gas – three phase production
PBU	Prudhoe Bay Unit
PO	Processed oil
ppb	Parts per billion
ppm	Parts per million
PR	Pitting rate, mpy
PTMAC	Point McIntyre
PW	Produced water
RT	Radiographic testing
SDI	Satellite drilling island
Sleeve	Mechanical repair
Slug catcher	First stage pressure vessel of OWG separation facility
STP	Seawater Treatment Plant
SW	Seawater
TRT	Tangential radiographic testing
UT	Ultrasonic testing
VSM	Vertical support member
WAG	Water alternating gas
WL/Well lines	Pipelines from the well head to manifold building
WLC	Weight loss coupon
WPM	Well pad manifold building
WSS	Walking speed survey
WTR	Combined seawater and produced water injection
X-country	Cross country

Appendix 2

(a) Work Plan
(b) Guide for Performance Metric Reporting

2000 Work Plan

Commitment to Corrosion Monitoring

Phillips Alaska, Inc.
BP Exploration (Alaska) Inc.

"BP and Phillips will, in consultation with ADEC, develop a performance management program for the regular review of BP's and Phillips' corrosion monitoring and related practices for non-common carrier North Slope pipelines operated by BP or Phillips. This program will include meet and confer working sessions between BP, Phillips and ADEC, scheduled on average twice per year, reports by BP and Phillips of their current and projected monitoring, maintenance and inspection practices to assess and to remedy potential or actual corrosion and other structural concerns related to these lines, and ongoing consultation with ADEC regarding environmental control technologies and management practices."

Work Plan Purpose:

The purpose of this work plan is to clearly define the purpose, scope, content, reporting requirements, roles and responsibilities, and milestones/timing for the development and implementation of the Corrosion Monitoring Performance Management Program required by Paragraph II.A.6 of the North Slope Charter Agreement.

Corrosion Monitoring Performance Management Program

Purpose: To provide for 'the regular review of BP and PAI's corrosion monitoring and related practices for non-common carrier North Slope pipelines' operated by BP or PAI.

'Corrosion Monitoring' specifically refers to the activity of monitoring pipeline corrosion rates via corrosion probes, corrosion coupons, internal pipeline inspections, and external pipeline inspections.

'Related practices' refers to the assessment of corrosion monitoring data and the associated response to the assessment, specifically chemicals, inspection, and repairs.

Scope: Non-common carrier North Slope pipelines operated by BP or Phillips Alaska, Inc.

"Non-common carrier pipelines" refer to Non-DOT-regulated pipelines. Included in this designation are cross-country and on-pad pipelines in crude, gas, and other hydrocarbon services, as well as, produced water and seawater service pipelines. In module and inter-module on pad piping are not considered part of the scope of this review program.

Content: This Corrosion Monitoring Performance Management Program consists of the following:

1. BP and PAI will "meet and confer" with ADEC twice per year, on average. These sessions will be "working sessions" where BP and PAI will inform ADEC of the following:

    A. Summary description of the inspection and maintenance practices used to assess and to remedy potential or actual corrosion, or other significant structural concerns relating to these lines, which have arisen from actual operating experience. This description will address overall areas of focus, the rationale for this focus, and the nature of monitoring and related practices used during the time since the last meeting. This description may be brief if strategies/focus areas have not changed since the last meeting.
    B. Summary overview of ongoing coupon and probe monitoring results.
    C. Summary overview of chemical optimization activities.
    D. Summary overview of ongoing internal inspection activities.
    E. Summary overview of ongoing external inspection activities.
    F. Summary overview of ongoing structural concerns
    G. Summary of conclusions drawn and responses taken to remedy potential or actual corrosion concerns relating to these lines.
    H. Review/discussion of corrosion or structural related spills and incidents
    I. Review the actions developed by the operator to address any corrosion performance trends that significantly exceed expected parameters.
    J. Summary of program improvements and enhancements, if applicable.
    K. Review of annual monitoring report (see below) at the next scheduled semi-annual meeting.

    The agenda for these meetings will also include an opportunity for open discussion and an opportunity for ADEC to ask questions, provide feedback, etc.

These meetings will be targeted for April and October of each year, although this timing can be adjusted upon the mutual agreement of BP, PAI, and ADEC. The location of the meetings will alternate between the parties.

2. BP and PAI will submit annual reports to ADEC, which will provide the status of current and projected monitoring activities. These reports will be issued on or before March 31st of each year, and reflect the prior calendar year. The following information will be provided:

   A. Annual bullet item reporting the progress of the Charter Agreement corrosion related commitment.
   B. A general overview of the previous year's monitoring activities.
   C. Metrics that depict coupon and probe corrosion rates.
   D. Metrics that characterize chemical optimization activities.
   E. Metrics that depict the number and type of internal/external inspections done, and, as applicable, the corrosion increases/rates and corresponding inspection intervals.
   F. Metrics that characterize the quantity and type of repairs made in response to the internal/external inspections done per the above paragraph.
   G. Metrics that depict the numbers and types of corrosion and structural related spills and incidents.
   H. A forecast of the next year's monitoring activities in terms of focus areas and inspection goals. These forecasts cannot be viewed as binding, as corrosion strategies are dynamic and priorities will change over the course of the year. However, changes in focus will be communicated to ADEC during the semi-annual meetings described above.

   Note: These reports will be presented in, and be part of, a comprehensive North Slope Charter Agreement status report.

3. In addition to the semi-annual "meet and confer" working sessions referenced above, BP and PAI will remain accessible to provide "ongoing consultation" to ADEC regarding environmental control technologies and management practices

'Environmental Control Technologies' refer to those technologies specifically related to corrosion monitoring and mitigation of the subject pipelines.

'Management practices' refer to corrosion monitoring and related practices as defined above.

4. During the semi-annual 'Meet and Confer' working meetings with BP and/or PAI, ADEC may use the services of a corrosion expert(s) (contracted from funds under Charter Commitment paragraph II.A.7) to assist in the review of performance trends and corrosion program features.

5. BP has assigned CIC Manager, R. Woollam/564-4437, and Phillips has assigned Kuparuk Engineering and Corrosion Supervisor M. Cherry and J. Huber/659-7384, to be the contacts responsible for ensuring these commitments are met, including ADEC notification of scheduled times for the semiannual presentations. The ADEC contact for this effort is (Pipeline Integrity Section Manager/S. Colberg/269-3078) who will notify interested personnel of the presentation times, maintain the reports for distribution to the public when requested and coordinate other issues relating to this commitment.

Annual Timetable

March 31st Annual Report

April 30th 1H Semi-Annual Review (Meet and Confer)

October 31st 2H Semi-Annual Review (Meet and Confer)

Guide for Performance Metric Reporting

General

- Different metrics show and reveal different aspects of the business and as a consequence there are rarely any 'right' or 'wrong' measures only 'right' or 'wrong' application and usage
- Summary statistics described below may be provided as a data appendix to the annual reports with the more pertinent tables and graphics being contained in the text as appropriate. The intent is not to clutter and interrupt the flow of the text with extraneous data
- Format of data, the order in which it is presented, etc. of each company's annual report may differ from the order presented below, depending on key messages and data context. For example, one company may choose to imbed Leak/Save data into an inspection graph as opposed to presenting the Leak/Save data in standalone tabular format.
- This is an initial document for implementation in the 2001 annual report to ADEC, it should be noted, that the guidelines provided below can and will be adjusted to improve the efficacy of the annual report and reporting mechanism

Timescale

- Data to be presented on an aggregate annualized basis
- Base year 1995 providing 5 year history before the start of the Charter Agreement and each year's annual report will add to time series starting in 1995

Equipment Classification

- **Well Line** Pipe work from the well head to the Well Pad Manifold Building, generally, the flow from a single well prior to commingling before transportation to the separation plant
- **Flow Line** Pipe work from the Well Pad Manifold Building to the Separation plant, generally, cross country and off pad pipe work which carries commingled flow to/from a well pad. Also, straight run flow from the wellhead to separation plant, without commingling, is classified at Flow Line pipe work
- **Exceptions** Pipe work not conforming to these basic definitions will be reported by exception

Service Definitions

- **Three Phase Production(3ø or OWG)** Basic reservoir fluids (O/W/G – oil, water and gas) produced from down hole through to the main separation plants that typically see only see changes in temperature and pressure from reservoir conditions and are therefore essentially un-separated

- **Seawater (SW)** Water sourced typically from the Beaufort Sea that has undergone primary treatment at the Seawater Treatment Plant. Note, that the seawater treatment plants differ across the slope in the primary treatment methods, most importantly oxygen removal, with both production gas and vacuum stripping being employed
- **Produced Water (PW)** The water produced with the primary reservoir 3 phase production after passing through the separation and treatment
- **Commingled Water (CW) or Mixed Water (MW)** Water which has been commingled and is therefore multi-sourced, this is typically a mix of SW and PW although other combinations exist in the operations on the North Slope
- **Gas (G)** Generic term for a number of different gas systems which transport essentially dry gas between facilities including fuel gas, lift gas and miscible injectant
- **Processed Oil (PO)** The oil/hydrocarbon produced with the primary reservoir 3 phase production after separation and treatment, this is primarily black oil but could include black oil plus NGL's

Basic Summary Statistics

- **Distribution** The data is fundamentally of log-normal distribution, with a lower limit of zero or no-change and potentially unlimited upper extent
- **Count** A count of the number of activities completed i.e. coupons pulled in a given year
- **Average** The average or mean for the criteria being summarized i.e. average corrosion rate
- **Target Value** The target value against which non-conformance, see below, is reported
- **Number Non-conformant** The number of items not conforming to the control criteria i.e. the number of coupons exceeding the control value
- **Percentage Non-conformance** The percentage not conforming to the control value as a percentage of the total

Weight Loss Coupon Data

Table below summarizes the reporting of weight loss coupon data for the major fields on the North Slope

	Well Lines	CCL/FL
3 ø Production	All	All
Seawater	GPB	All
Prod. Water	GPB	GPB
Commingled Water	All	All

The data sets to be provided for both general corrosion rates and pitting rates are,

- Count of coupons
- Average corrosion rate
- Number non-conformant

- % Conformant i.e. 1 minus the % non-conformant

A corrective action list for non-conformant flow lines (FL/LDF/CCL/CLs) will also be provided.

Internal Inspection Data

Table below summarizes the reporting of internal corrosion inspection data for the major fields on the North Slope

	Well Lines	CCL/FL
3 ø Production	All	All
Commingled Water	All	All

Note that no distinction will be made between water services across the North Slope since in many cases the service is variable making meaningful analysis and aggregation difficult.

The data sets to be provided for internal inspection are,

- Count of inspections
- Number of increases on repeat inspection locations
- Percentage of increases on repeat inspections

A corrective action list for flow lines (FL/LDF/CCL/CLs) with inspection increases will also be provided.

Corrosion Inhibition

The corrosion inhibition program is to be reported as the target and actual total annual gallons and gallons per day, and as concentration, ppm, based on a field wide average.

External Corrosion Inspection

External corrosion inspection program is to be reported as an aggregate of all piping systems without distinction or differentiation of service and equipment type with a summary of the overall program status.

The data sets to be provided for external inspection are,

- Count of inspected location
- Number of corroded locations
- Percentage of inspection locations corroded

Repair and Leak Statistics

The repair and leak/spill statistics to be reported for each year plus the historical trend back to 1995 consistent with other performance metrics. The basic definitions,

- **Leak/Spill** An agency reportable leak/spill for the pipelines covered under the Charter Agreement which was caused by corrosion and/or erosion

- **Save** A location which required repair action as a result of corrosion and/or erosion damage but which was found through inspection prior to causing a leak/spill

The data sets to be provided for Repair/Leak statistics,

- Count of Leaks/Saves by flow line and well lines
- Summary of leak/spill causes

Below Grade Piping

The data sets to be provided for Below Grade Piping (BGP) program,

- Number of segments/crossings inspected broken out by inspection method
- Number with anomalies and severity of anomaly

Results of casing digs, visual casing inspections and casing clean-out to be reported as appropriate.

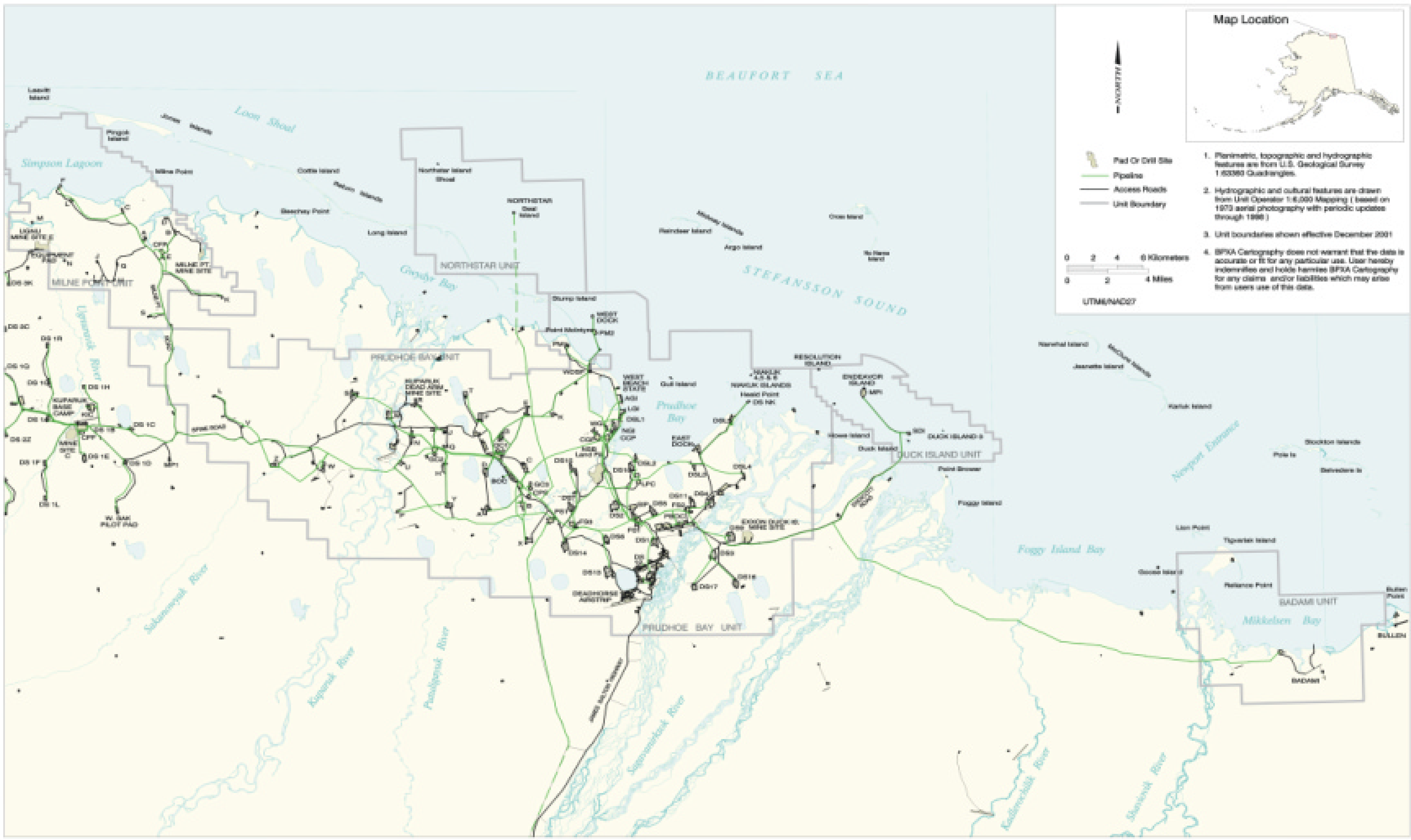
Other Programs

Reporting of ER probe, smart pigging, maintenance pigging, structural issues, and details of individual spill incidents to be reported as dictated by the current year's program activity.

Appendix 3

(a) Map of the North Slope
(b) North Slope Oil Field Facility and Piping Summary

BPXA OPERATING UNITS - NORTH SLOPE, ALASKA



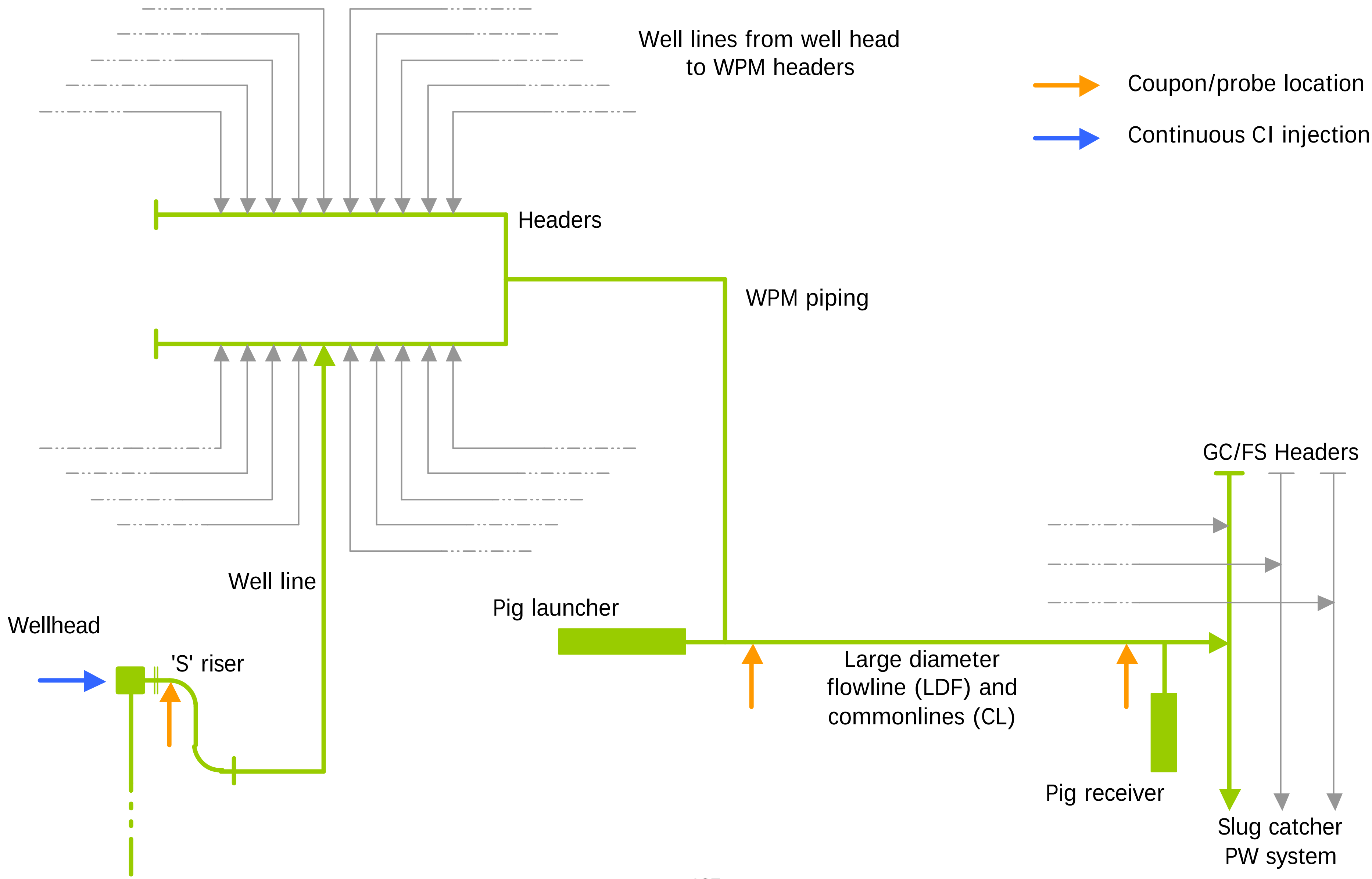
BP North Slope Operations	Field Data (current 1/01)	
Greater Prudhoe Bay	Field Area	150,000 acres
	Original Oil in Place (Gross)	25 billion barrels
	Original Gas in Place (Gross)	47 trillion Std. Cu Ft
	Oil Production Wells	1,080
	Gas Injection Wells	36
	Water Injection Wells	174
	Major Separation Plants	6
	Major Gas Handling Plants	2
	Major Water Handling Plants	3
	Miles of Pipelines (approximate)	1,300
Midnight Sun	Field Area	3,000 acres
	Original Oil in Place (Gross)	0.06 billion barrels
	Original Gas in Place (Gross)	0.1 trillion Std Cu Ft
	Oil Production Wells	2
	Water Injection Wells	1
	Miles of Pipelines (approximate)	4
Aurora	Field Area	10,000 acres
	Original Oil in Place (Gross)	0.1 billion barrels
	Original Gas in Place (Gross)	0.1 trillion Std Cu Ft
	Oil Production Wells	5
	Miles of Pipelines (approximate)	1
Pt. McIntyre	Field Area	8,000 acres
	Original Oil in Place (Gross)	0.8 billion barrels
	Original Gas in Place (Gross)	0.9 trillion Std Cu Ft
	Oil Production Wells	59
	Gas Injection Wells	1
	Water Injection Wells	15
	Miles of Pipelines (approximate)	6
Lisburne	Field Area	30,000 acres
	Original Oil in Place (Gross)	1.8 billion barrels
	Original Gas in Place (Gross)	0.3 trillion Std Cu ft
	Oil Production Wells	74
	Gas Injection Wells	4
	Major Separation Plants	1
	Miles of Pipelines (approximate)	27
Niakuk & Western Niakuk	Field Area	1,900 acres
	Original Oil in Place (Gross)	0.2 billion barrels
	Original Gas in Place (Gross)	0.1 trillion Std Cu Ft
	Oil Production Wells	18
	Water Injection Wells	7
	Miles of Pipelines (approximate)	6

BP North Slope Operations	Field Data (current 1/01)	
Milne Point	Field Area	36,454 acres
	Original Oil in Place (Gross)	0.92 billion barrels
	Oil Production Wells	107
	Gas/Water Injection Wells	59
	Source Water Wells	8
	Major Separation Plants	1
	Miles of Pipelines (approximate)	55
Schrader Bluff	Field Area	28,000 acres
	Original Oil in Place (Gross)	1.97 billion barrels
	Oil Production Wells	49
	Gas\Water Injection Wells	14
	Source Water Wells	3
	Miles of Pipelines (approximate)	15
Eider	Field Area	300 acres
	Original Oil in Place (Gross)	0.013 billion barrels
	Original Gas in Place (Gross)	0.052 trillion Std Cu Ft
	Oil Production Wells	1
	Gas Injection Wells	1
	Miles of Pipelines (approximate)	.5
Endicott	Field Area	8,800 acres
	Original Oil in Place (Gross)	1.1 billion barrels
	Original Gas in Place (Gross)	1.4 trillion Std Cu Ft
	Oil Production Wells	47
	Gas Injection Wells	5
	Water Injection Wells	21
	Major Separation Plants	1
	Miles of Pipelines (approximate)	52
Sag Delta North	Field Area	380 acres
	Original Oil in Place (Gross)	0.014 billion barrels
	Oil Production Wells	2
	Gas Injection Wells	2
	Miles of Pipelines (approximate)	.5
Badami	Original Oil in Place (Gross)	0.160 billion barrels
	Oil Production Wells	6
	Gas Injection Wells	2
	Major Separation Plants	1
	Miles of Pipelines (approximate)	50
Northstar	Field Area	38,000 acres
(current 3/02)	Original Oil in Place (Gross)	.176 billion barrels
	Oil Production Wells	4
	Disposal Injection Wells	1
	Gas Injection Wells	2
	Major Separation Plants	1
	Miles of Pipelines (approximate)	30

Appendix 4

Facilities Schematic

Facility Schematic



Appendix 5

Data Tables

Appendix 5 – Data Tables

Introduction

With the introduction of single-operatorship at Greater Prudhoe Bay one of the major problems faced by the Corrosion Inspection and Chemical (CIC) Group was the integration of two historical data sets for inspection, corrosion monitoring and corrosion mitigation information.

There has been a significant investment in resources in order to bring together these two different histories from incompatible databases based on early 1990's technology.

As of the end of 2002, the inspection program and corrosion-monitoring program have largely been integrated into a single database on an Oracle platform with a user interface in VisualBasic.

The database development effort has involved a dedicated team of software developers and database administration but also significant resources from within the CIC Group. The program is currently a "work in progress" and in 2003 BP/CIC will continue work on the development of chemical management, electronic data recording, tank and vessel, and standard reporting modules.

The data is continuously monitored for integrity, quality and consistency, as a consequence any errors detected are corrected as they are found. In addition, as better analysis tools become available through further integration then records are amended to reflect the improved level of analysis.

As a result of the ongoing quality effort and the tracking of production/service changes, this is a 'live' database and therefore as the system changes then the records returned will change. The following are some of reasons why returned values change through time,

Quality Control and Audit A fundamental design philosophy for the database was that errors should be corrected through time as they are discovered. Therefore as the database is used and the quality control rules and procedures applied, data-entry, translation and record-keeping errors are eliminated.

Equipment Service Changes The database tracks active, in or out-of-use equipment, and equipment service changes. As a piece of equipment moves through different services and different status, then the data in the database tracks the equipment status.

Transition Issues As noted above, the two historical databases, heritage East and heritage West, were incompatible with very different structures and data fields. Therefore these have had to be translated to the new system. As the quality control and audit tools are applied to the translated data, error and mistranslations are removed.

Time The database is in active use with data being added everyday, given that there is sometimes a time delay between the reporting date and entry date then the data totals can and do change.

BU	Equip	Service	Metric	1995	1996	1997	1998	1999	2000	2001	2002
GPB	FL	OIL	WLC	1432	1558	1602	1494	1526	1449	1302	1323
GPB	FL	OIL	Ave CR	1.38	0.84	0.49	0.49	0.31	0.42	0.34	0.33
GPB	FL	OIL	SD CR	6.94	3.93	2.07	3.76	0.57	0.84	0.90	0.68
GPB	FL	OIL	WLC < 2	1303	1476	1558	1464	1512	1409	1282	1310
GPB	FL	OIL	% <2 mpy	91%	95%	97%	98%	99%	97%	99%	99%
GPB	FL	PW/SW	WLC	122	105	113	90	100	81	60	59
GPB	FL	PW/SW	Ave CR	4.82	3.04	0.65	0.60	0.72	0.54	0.56	0.86
GPB	FL	PW/SW	SD CR	11.87	7.49	1.62	0.99	1.55	1.30	1.52	2.48
GPB	FL	PW/SW	WLC < 2	94	87	105	84	91	74	56	53
GPB	FL	PW/SW	% <2 mpy	77%	83%	93%	93%	91%	91%	93%	90%
GPB	FL	PO	WLC	24	34	44	32	34	36	22	26
GPB	FL	PO	Ave CR	0.13	0.23	0.13	0.16	0.14	0.17	0.08	0.09
GPB	FL	PO	SD CR	0.17	0.29	0.19	0.11	0.05	0.07	0.06	0.03
GPB	FL	PO	WLC < 2	24	34	44	32	34	36	22	26
GPB	FL	PO	% <2 mpy	100%	100%	100%	100%	100%	100%	100%	100%
GPB	WL	OIL	WLC	5265	6472	6536	6075	5729	5856	4472	4127
GPB	WL	OIL	Ave CR	2.76	2.27	0.97	0.73	0.57	0.78	0.69	0.63
GPB	WL	OIL	SD CR	6.96	6.08	2.32	3.74	1.31	1.55	1.74	1.20
GPB	WL	OIL	WLC < 2	3713	4864	5754	5703	5489	5374	4141	3819
GPB	WL	OIL	% <2 mpy	71%	75%	88%	94%	96%	92%	93%	93%
GPB	WL	Majority PW	WLC	829	976	1073	959	733	699	651	398
GPB	WL	Majority PW	Ave Rate	0.80	0.86	0.35	2.46	0.47	0.27	1.44	0.33
GPB	WL	Majority PW	SD Rate	1.19	8.68	2.26	12.09	1.65	0.43	8.61	0.95
GPB	WL	Majority PW	WLC<2mpy	760	947	1047	879	709	690	592	383
GPB	WL	Majority PW	%<2mpy	92%	97%	98%	92%	97%	99%	91%	96%
GPB	WL	100% PW	WLC	485	604	717	718	521	459	472	288
GPB	WL	100% PW	Ave Rate	0.81	1.10	0.35	2.91	0.41	0.30	1.92	0.32
GPB	WL	100% PW	SD Rate	1.19	10.98	2.62	13.67	1.51	0.51	10.07	1.04
GPB	WL	100% PW	WLC<2mpy	447	589	703	655	509	450	415	279
GPB	WL	100% PW	%<2mpy	92%	98%	98%	91%	98%	98%	88%	97%
GPB	WL	Majority SW	WLC	311	162	56	44	82	98	44	25
GPB	WL	Majority SW	Ave Rate	2.67	3.25	0.65	0.96	1.82	1.78	6.01	6.58
GPB	WL	Majority SW	SD Rate	3.89	5.26	1.20	1.14	2.36	2.77	6.88	5.27
GPB	WL	Majority SW	WLC<2mpy	197	110	53	38	61	78	16	7
GPB	WL	Majority SW	%<2mpy	63%	68%	95%	86%	74%	80%	36%	28%
GPB	WL	100% SW	WLC	183	78	52	44	70	86	16	21
GPB	WL	100% SW	Ave Rate	2.88	2.86	0.68	0.96	1.82	1.89	1.92	7.46
GPB	WL	100% SW	SD Rate	4.48	5.39	1.24	1.14	2.50	2.93	1.07	5.28
GPB	WL	100% SW	WLC<2mpy	124	54	49	38	52	68	12	5
GPB	WL	100% SW	%<2mpy	68%	69%	94%	86%	74%	79%	75%	24%

Table 5.1 GPB Flow and Well Line General Corrosion Rate Data Summary

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BU	Equip	Service	Metric	1995	1996	1997	1998	1999	2000	2001	2002
GPB	FL	OIL	P WLC	1432	1558	1600	1494	1526	1449	1302	1323
GPB	FL	OIL	Ave P CR	9.3	7.7	6.8	2.9	1.6	1.9	1.3	0.7
GPB	FL	OIL	SD P CR	24.3	15.0	14.1	6.7	6.1	7.7	10.5	3.9
GPB	FL	OIL	P WLC < 20	1308	1465	1543	1468	1503	1416	1290	1310
GPB	FL	OIL	% P WLC <20mpy	91%	94%	96%	98%	99%	98%	99%	99%
GPB	FL	PW/SW	P WLC	122	105	113	90	100	81	60	59
GPB	FL	PW/SW	Ave P CR	23.1	17.8	12.2	8.5	5.0	7.5	8.8	5.1
GPB	FL	PW/SW	SD P CR	31.3	28.4	17.0	16.5	12.1	20.5	33.1	13.8
GPB	FL	PW/SW	P WLC < 20	83	83	103	83	92	73	55	54
GPB	FL	PW/SW	% P WLC <20mpy	68%	79%	91%	92%	92%	90%	92%	92%
GPB	FL	PO	P WLC	24	34	44	32	34	36	22	26
GPB	FL	PO	Ave P CR	1.9	2.6	3.7	2.2	1.3	1.4	1.1	0.8
GPB	FL	PO	SD P CR	3.4	4.6	4.3	5.7	2.4	3.5	3.5	3.9
GPB	FL	PO	P WLC < 20	24	34	44	31	34	36	22	26
GPB	FL	PO	% P WLC <20mpy	100%	100%	100%	97%	100%	100%	100%	100%
GPB	WL	OIL	P WLC	5258	6469	6536	6075	5722	5850	4460	4105
GPB	WL	OIL	Ave P CR	11.5	11.9	5.4	3.2	2.9	3.2	2.1	1.9
GPB	WL	OIL	SD P CR	32.3	29.1	14.9	9.2	8.1	8.4	6.6	6.0
GPB	WL	OIL	P WLC < 20	4592	5582	6257	5923	5600	5678	4365	4052
GPB	WL	OIL	% P WLC <20mpy	87%	86%	96%	97%	98%	97%	98%	99%
GPB	WL	Majority PW	P WLC	829	976	1073	959	733	699	651	398
GPB	WL	Majority PW	Ave P CR	20.2	15.0	9.6	20.8	8.9	4.7	6.8	3.2
GPB	WL	Majority PW	SD P CR	29.1	29.6	29.0	58.7	26.2	9.7	17.6	9.6
GPB	WL	Majority PW	P WLC < 20	574	802	968	800	667	670	571	387
GPB	WL	Majority PW	% P WLC <20mpy	69%	82%	90%	83%	91%	96%	88%	97%
GPB	WL	100% PW	P WLC	485	604	717	718	521	459	472	288
GPB	WL	100% PW	Ave P CR	20.7	15.1	7.6	22.3	7.1	4.7	8.2	3.0
GPB	WL	100% PW	SD P CR	31.0	30.2	19.3	64.3	25.6	11.1	20.0	10.3
GPB	WL	100% PW	P WLC < 20	331	500	659	600	486	438	399	279
GPB	WL	100% PW	% P WLC <20mpy	68%	83%	92%	84%	93%	95%	85%	97%
GPB	WL	Majority SW	P WLC	311	162	56	44	82	98	44	25
GPB	WL	Majority SW	Ave P CR	11.6	16.9	1.5	1.5	5.6	6.6	18.8	30.5
GPB	WL	Majority SW	SD P CR	15.5	23.1	4.5	2.3	8.2	10.4	18.6	28.1
GPB	WL	Majority SW	P WLC < 20	257	115	55	44	80	92	24	14
GPB	WL	Majority SW	% P WLC <20mpy	83%	71%	98%	100%	98%	94%	55%	56%
GPB	WL	100% SW	P WLC	183	78	52	44	70	86	16	21
GPB	WL	100% SW	Ave P CR	9.4	10.1	0.5	1.5	5.2	5.6	9.1	31.6
GPB	WL	100% SW	SD P CR	13.5	19.9	2.2	2.3	8.5	6.4	7.3	29.5
GPB	WL	100% SW	P WLC < 20	156	62	52	44	68	82	14	12
GPB	WL	100% SW	% P WLC <20mpy	85%	79%	100%	100%	97%	95%	88%	57%

Table 5.2 GPB Flow and Well Line Pitting Rate Data Summary

BU	Type	Service	Result	1995	1996	1997	1998	1999	2000	2001	2002
GPB	FL	OIL	I	370	934	1176	411	239	66	60	103
GPB	FL	OIL	NC	15271	15813	16603	14891	12052	8239	7145	8829
GPB	FL	OIL	NL	3644	2122	1979	444	367	148	1767	1867
GPB	**FL**	**OIL**	**Total**	**19285**	**18869**	**19758**	**15746**	**12658**	**8453**	**8972**	**10799**
GPB	FL	WTR	I	171	124	154	192	72	17	43	137
GPB	FL	WTR	NC	1164	1076	1125	1561	1560	720	1092	1174
GPB	FL	WTR	NL	422	116	141	88	77	61	354	390
GPB	**FL**	**WTR**	**Total**	**1757**	**1316**	**1420**	**1841**	**1709**	**798**	**1489**	**1701**
GPB	**FL**	**Total**	**Total**	**21042**	**20185**	**21178**	**17587**	**14367**	**9251**	**10461**	**12500**
GPB	WL	OIL	I	641	918	877	605	311	263	214	276
GPB	WL	OIL	NC	2459	3507	3401	4092	3616	4134	5494	7154
GPB	WL	OIL	NL	975	1799	1987	725	574	530	2498	3504
GPB	**WL**	**OIL**	**Total**	**4075**	**6224**	**6265**	**5422**	**4501**	**4927**	**8206**	**10934**
GPB	WL	WTR	I	224	262	201	216	74	128	77	125
GPB	WL	WTR	NC	987	1500	1049	1607	1430	1718	1270	1117
GPB	WL	WTR	NL	620	360	635	223	176	260	490	523
GPB	**WL**	**WTR**	**Total**	**1831**	**2122**	**1885**	**2046**	**1680**	**2106**	**1837**	**1765**
GPB	**WL**	**Total**	**Total**	**5906**	**8346**	**8150**	**7468**	**6181**	**7033**	**10043**	**12699**
GPB	**Total**	**Total**	**Total**	**26948**	**28531**	**29328**	**25055**	**20548**	**16284**	**20504**	**25199**

Table 5.3 GPB Flow and Well Line Inspection Data

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